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PROSPECTS FOR INCREASING THE DIRECT USE OF COAL IN INDUSTRIAL BOILERS

by

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The report gives a comprehensive evaluation of factors (environmental, technical, economic, and institutional) influencing solid coal use in industrial boilers. Trends in coal use, recent legislative warrants, and technical and logistic problems in coal use at industrial plants are reviewed. Demographic aspects of the existing industrial boiler population are examined, and regional patterns in fuel consumption, boiler deployment, and the location of major energy consuming industries are identified. Six technologies and five alternate groups of the technologies are compared to the year 2000 on the basis of resource requirements and emissions. Technologies considered are conventional combustion in both a spreader-stoker boiler and with flue-gas desulfurization, fluidized-bed combustion, low-Btu gasification, and physical coal cleaning (alone and combined with the above technologies). Air emissions are further assessed from the perspective of existing air quality problems in industrial areas. Capital and annual costs for each technology are also compared. Sensitivity analysis is included to detail the extent to which varying operating parameters affect steam cost. Fuel choices are evaluated on industry- and region-specific bases. Finally, results of analyses are interpreted from the perspective of achieving environmental and energy goals.

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Combustion	Industrial Boilers	21B
Boilers		13A
Demography		08F
Fuel Consumption		21K

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DISCLAIMER

This report has been prepared as part of the national Coal Technology Assessment program and has been reviewed by the Office of Environmental Engineering and Technology, U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the U.S. Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FOREWORD

Although the cost data in this Coal Technology Assessment report are somewhat out of date (most of it developed prior to 1980), it is advised that those persons using this report update the data of interest to them. The report is issued in its present form since it is believed that a broad sector of the technical community will find it useful, and the conclusions are valid.

AB Craig for

Frank T. Princiotta
Director, IERL-RTP

ABSTRACT

This is the first major report from the national Coal Technology Assessment program; this report provides a comprehensive evaluation of the factors—environmental, technical, economic, and institutional—influencing the use of solid coal in industrial boilers. The historical trends in the use of coal, recent legislative warrants, and the technical and logistical problems in using coal at industrial plants are briefly overviewed in order to define the context within which an expansion in the use of coal must occur. Demographic aspects of the existing industrial boiler population are examined to further define this context, and to identify regional patterns in fuel consumption, boiler deployment, and in the location of major energy consuming industries. A nominal 6 quad (6.0 × 10^{15} Btu)* level of coal use in industrial boilers is assumed to be attained by the year 2000. Six technologies, and five alternative groupings of these technologies, were compared on the basis of resource requirements and emissions. The technologies considered were conventional combustion in a spreader-stoker boiler, conventional combustion with flue-gas desulfurization, fluidized-bed combustion, low-Btu gasification, and physical coal cleaning (alone and in combination with the above technologies). Air emissions are further assessed from the perspective of existing air quality problems in areas of industrial concentration. Potential difficulties in gaining offsets are addressed. Capital and annual costs for each of the technologies are also compared. Sensitivity analysis is included to detail the extent to which variations in operating parameters affect the cost of steam. Fuel choice decisions are evaluated on an industry and region specific basis. Finally, the results of these analyses are interpreted from the perspective of achieving environmental and energy goals.

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*Although EPA's policy includes use of metric units, this report uses nonmetric units at times when it is felt they will be more readily visualized by the reader. A metric conversion table is provided on page xii of this report, for readers more familiar with that system.

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METRIC CONVERSION TABLE

EPA policy is to express all measurements in Agency documents in metric units. When implementing this policy results in undue cost or loss of clarity, conversion factors for the particular nonmetric units used in the document are provided. These factors are:

BRITISH		METRIC
Multiply	**By**	**To Obtain**
inch	2.54×10^{-2}	meter (m)
feet	3.048×10^{-1}	meter
cubic feet (ft^3)	2.83168×10^{-2}	cubic meter (m^3)
ounce (troy)	3.1103×10^{1}	gram (g)
pound (lb)	4.536×10^{-1}	kilogram (kg)
ton	9.07×10^{-1}	tonne (1000 kg)
lb/ft^3	1.60256×10^{-2}	g/cm^3
acre	4.046×10^{3}	square meter (m^2)
square mile	2.59	square kilometer
gallon	3.785	liter
barrel	1.39×10^{-1}	tonne
	1.79×10^{-2}	liter (gasoline)
British thermal unit (Btu)	1.055×10^{3}	joule (J)
Quad (10^{15} Btu)	1.055×10^{9}	gigajoule (GJ)

TEMPERATURE CONVERSION

Fahrenheit (°F) to Celsius (°C)

Temperature (°C) = 5/9 (°F − 32)

Fahrenheit (°F) to Kelvin (°K)

Temperature (°K) = 5/9 (°F − 32) + 273

GLOSSARY

Atomic Energy Act of 1954: This act established the role of the Federal Government in the commercialization of nuclear power. Safety regulations, financing provisions and liabilities, and creation of the (old) Atomic Energy Commission (AEC) were stipulated.

best available control technology (BACT): BACT is the means by which the maximum emission reduction can be achieved through the application of proven control technologies, fuel pre-treatment, or process modifications, after taking into account the economic, energy, environmental, and other costs of control. BACT is always as stringent as or more stringent than NSPS.

British thermal unit (Btu) (including relationship to pounds of steam): Originally defined as the heat required to raise the temperature of 1 pound of water by 1° F, the Btu has recently been redefined as 1/860 International kilowatt-hour. One pound of steam is roughly equivalent to 1000 Btu at the temperature and pressure characteristic of the technologies investigated in this report.

cast iron boiler: A cast iron boiler consists of a furnace situated in a water jacket through which combustion gases pass by means of flues, and thereby transfer heat to the water. Generally, cast iron boilers produce only hot water or low pressure steam.

Clean Air Act and Amendments of 1977 (CAA): The CAA is the most recent of a series of Federal legislation aimed at protecting the public's health and welfare from the effects of air pollution. It establishes mechanisms to clean up areas of the country not now meeting the minimum air quality standards specified in the act. The Environmental Protection Agency is charged with the setting of regulations and the administration of the act.

Coal Technology Assessment (CTA): The CTA is a comprehensive assessment of the use of coal in the United States over the next several decades. This assessment is sponsored by the EPA's Office of Research and Development.

conventional combustion (CC): As used in this report, CC is the burning of pulverized or lump coal that has had little or no cleaning, and that employs no control technologies for removing sulfur dioxide (SO_2) from the air emissions.

deregulation: Deregulation is the act of removing existing regulations, most often justified on the basis of increased economic efficiency.

emission density zoning (EDZ): EDZ is a proposed method for allowing growth in attainment (PSD) areas in which theoretical air quality increments establish maximum allowable emission limits per unit of land area. Emission limits rather than ambient air quality would serve as the basis for permitting under prevention of significant deterioration (PSD) guidelines.

Energy Supply and Environmental Coordination Act of 1974 (ESECA): ESECA provided for the prohibition of natural gas or petroleum use in power plants, subject to determinations by the administrator of the (then) Federal Energy Administration. In addition, data gathering and allocation of low-sulfur fuels were stipulated in the act. ESECA was superseded by the Powerplant and Industrial Fuel Use Act (FUA) of 1978.

environmental assessment (EA): An EA is one of a continuing series of studies sponsored by EPA's Office of Research and Development, the purposes of which are 1) to identify and to characterize discharges from various technologies; 2) to evaluate pollution control and waste disposal options for these discharges, particularly within the framework of existing environmental standards; and 3) to assign priorities for further process or control technology development.

Federal Energy Regulatory Commission (FERC): FERC is the governmental body responsible for setting price guidelines for regulated energy supplies.

fire-tube boiler: This type of boiler transfers the heat of combustion through tubes submerged in a water basin. Locomotive boilers, for example, are of the fire-tube type.

flue-gas desulfurization (FGD): FGD ("scrubbing") is a means by which sulfur dioxide is removed from stack gases after conventional combustion, usually through weak acid-base reactions employing an alkaline sorbent.

fluidized-bed combustion (FBC): FBC is a process in which air is injected from below the combustion chamber to keep the fuel burning in a suspended bed. Selective sorbents may be added to remove sulfur during the combustion process.

"grassroots" facilities: These are completely new facilities that are built from scratch.

growth allowance: This method, which places "excess" control on existing sources in nonattainment areas to make ambient air cleaner than the NAAQS, allows growth in minor sources or other flexibility in permitting without violating the NAAQS ceiling.

incremental pricing: This type of pricing incorporates a phased approach to price increases and is used especially in the gradual transition to deregulated prices.

inhalable particulate (IP): IP consists of small solid particles or aerosols that result from incomplete combustion of fuels, chemical reactions, or entrained dust. Inhalable particulates are defined as the size range of particles small enough to become embedded in the lung.

liquefied natural gas (LNG): LNG is a form of natural gas made to condense or "liquefy" by subjection to high pressures, thus reducing the volume of gas requiring transport. Natural gas is most often liquefied for overseas transport.

load factor: This term describes the fraction of total capacity, and the fraction of time, that a plant is used, averaged over a given time span, usually one year.

low-Btu gasification: In this process, coal is coverted to a mixture of combustible and incombustible gases, with an energy content of approximately 200 Btu per standard cubic foot.

lowest achievable emission rates (LAER): Similar to BACT, LAER specifies emission reductions for new sources that are based solely on the technical feasibility of control.

National Ambient Air Quality Standards (NAAQS): NAAQS are minimum standards for ambient air quality based on concentration. NAAQS have been established under the CAA for sulfur dioxide (SO_2), nitrogen oxides (NO_x), cadmium, lead, non-methane hydrocarbons, photochemical oxidants, total suspended particulates (TSP), and carbon monoxide (CO). Two standards exist: one to protect human health; and a second, which is more stringent, to protect vegetation, materials, and so on.

National Energy Act of 1978: This act is the first attempt at a comprehensive, national energy policy, and consists of five major acts covering conservation, priorities for energy use, the pricing of energy, and allowable supplies of fossil fuels for various applications of energy (*See also* National Gas Policy Act; Powerplant and Industrial Fuel Use Act).

National Gas Policy Act of 1978 (NGPA): The NGPA provides for gradual price deregulation of natural gas and establishes priority users for natural gas in the case of shortages.

National Interim Primary Drinking Water Standards (NIPDWS): NIPDWS are applicable to public water systems and establish maximum concentrations of inorganic, organic, microbiological, and radionuclide contaminants in drinking water, as well as turbidity levels.

Natural Gas Act of 1938 (NGA): This act was the first piece of Federal legislation to regulate natural gas prices.

New Source Performance Standards (NSPS): NSPS are emission limitations for new, major sources, such as powerplants, coke ovens, industrial boilers, copper smelters, and so on. Emission reductions must be continuous.

non-attainment area: This is a designation for an area that exceeds the national ambient air quality standards (NAAQS) for a given air pollutant.

OBERS projections: These projections are a long-term economic forecast made jointly by the Office of Business Economics in the Department of Commerce and the Economic Research Service of the Department of Agriculture.

offset policy: Under this policy, new sources or modifications may be required to obtain, by some means, a better than one-to-one emission reduction from other sources in the applicable area, before they are granted a permit to construct.

opportunity costs: This economic term measures the potential profit that is foregone by making one investment choice over another.

"packaged" boilers: These boilers are constructed off-site and shipped to the point of use as a complete unit.

physical coal cleaning (PCC): PCC is a process by which coal is crushed and sized, then floated in a liquid medium, with impurities sinking away from the coal. The coal is then mechanically dewatered and dried. Many variations on this process exist, depending on the coal type and what is to be cleaned.

Powerplant and Industrial Fuel Use Act of 1978 (FUA): This act is one of the five acts constituting the National Energy Act. The purposes of the FUA are to conserve natural gas and petroleum for uses other than electric utility, industrial, or commercial steam raising and/or electricity generation, fostering instead the use of coal or alternative fuels.

prevention of significant deterioration (PSD): PSD is the primary mechanism under the CAA to ensure that future growth does not significantly degrade air quality in areas that are cleaner than the NAAQS.

Primary Drinking Water Standards: *See* National Interim Primary Drinking Water Standards.

quad (Q): The term quad (Q) refers to a unit of measurement equal to 1 × 10^{15} (quadrillion) British thermal units (Btu) or 1.05 × 10^9 gigajoules (GJ). One Q is roughly equivalent to over 170 million barrels of crude oil (24 million metric tons), or about 42 million short tons of bituminous coal (38 million metric tons), or about 1 trillion cubic feet of natural gas (26.5 billion cubic meters).

reasonably available control technologies (RACT): RACT consists of emission controls applied to existing facilities, which are generally less stringent or costly than BACT.

Resource Conservation and Recovery Act of 1976 (RCRA): RCRA establishes the role of the Federal Government in issuing standards and guidelines for the transport and disposal of wastes, both hazardous and solid. In addition, the act provides for Federal support for research and development of new methods to conserve resources and to recover resources from wastes. RCRA supersedes the Solid Waste Disposal Act of 1965.

Solid Waste Disposal Act of 1965: This act provided for research, training, and demonstration grants to State and local agencies engaged in waste disposal, and provided monies for the construction of new waste disposal facilities and for the upgrading of existing disposal sites. The act was superseded by the Resource Conservation and Recovery Act (RCRA) of 1976.

spreader-stoker boiler: This is a type of boiler where mechanical feeders and distributing devices feed solid fuel (in this case, coal) into the boiler.

Standard Industrial Classification (SIC): SIC is a system of classifying industrial establishments by the type of activity in which they are engaged in accordance with the composition and structure of the economy. They are prepared by the Executive Office of the President, Office of Management and Budget.

State Implementation Plan (SIP): A SIP is a plan submitted by each State to EPA outlining how the NAAQS will be achieved for any nonattainment area in the State.

sulfur dioxide (SO_2) emissions: SO_2 is created when sulfur in the fuel combines with oxygen during combustion. SO_2 emissions are the resulting pollutant in the flue gases and thus are a major target of clean air legislation.

total suspended particulate (TSP): TSP consists of all particles or aerosols measured as a concentration in ambient air.

Toxic Substances Control Act (TSCA): TSCA provides for the testing of manmade substances to determine if their use or manufacture poses health risks. A substance may be prevented from manufacture or its use may be subject to stringent control, should it prove harmful.

trajectories: Trajectories are the complete sequence of operations from obtaining a source of energy to converting it to a useful application. In this report, a trajectory is specifically the succession of operations from mining coal to its use as a boiler fuel.

water-tube boiler: This type of boiler uses water-tubes as a heat transfer mechanism in which hot combustion gases transfer heat to water in the tubes through conduction.

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CHAPTER 1

INTRODUCTION AND SUMMARY

Over 35 percent of the total U.S. energy budget is consumed in the industrial sector; this amount was equivalent to 22 Q in 1978. Forty percent of the energy used by the industrial sector is devoted to producing steam. Steam is used to power machinery, heat chemical reactors, cook foods, distill liquids, provide reducing atmospheres, and so on. Because of its many applications, steam is the prime mover in the nation's multifaceted industries. However, the quantity of steam used and its percentage of total energy use vary markedly among industries. For example, equipment manufacturing and the stone, clay, and glass industries use a relatively small amount of steam; whereas, the food and paper industries are among the largest users. Over one-half million boilers, ranging in size from small prefabricated "packaged" units to units large enough to rival those turning turbines in electric utilities, produce steam for U.S. industries. Boilers are deployed in every state, every industry, and can be run with all types of energy carriers--solid, liquid, gas, and electric--and all fuels--coal, petroleum, natural gas, uranium, solar, wood, and waste. Thus, modifying the fuels and energy carriers used to raise steam in boilers provides a significant opportunity for substituting more plentiful energy supplies for those that are becoming scarce.

As part of the national Coal Technology Assessment (CTA) program, which is an ongoing comprehensive assessment of the use of coal over the next several decades, a study of industrial boilers has been undertaken to examine possibilities for using coal, which is a plentiful resource, as a boiler fuel instead of scarce oil and natural gas supplies. Our efforts to evaluate the potential for coal use are based on increasingly tight energy supplies and the national desire to reduce dependence on imported energy supplies.

IMPORTANCE OF INDUSTRIAL BOILERS

Approximately one-sixth of all energy consumed in the U.S. is used in industrial boilers to raise steam. The industrial facilities in which these boilers operate are located predominantly in densely populated areas and are concentrated regionally. In part, the regional concentration of industry reflects historical access to markets, transportation, labor, and raw materials. Industrial development, in turn, stimulates the need for more homes and the growth of commercial enterprises. Because industry is the major employer of the nation's work force, decisions that affect industry affect the community as well.

Policies affecting the choice of fuel for industrial boilers have widespread ramifications. The use of natural gas or oil places fewer demands on transportation, requires less pollution control, and requires less space for storage, than does the use of coal. Oil and gas are easier to handle than coal. Boilers fired by natural gas or oil are easier to operate and maintain. If policies favoring the increased use of coal in industrial boilers are made, the possible risks to local communities from increased pollution will need to be managed. Further, the impacts on industrial performance will need to be assessed and the reactions of industrial decision makers anticipated.

Within the context of regional, local, and industrial impacts, and national policies, a comprehensive investigation of coal use in industrial boilers gains relevance. This report provides such an assessment.

OBJECTIVES OF THE STUDY

Four major objectives have guided the analysis of our study:

- To test the complex relationship between two pieces of national legislation: the Clean Air Act and Amendments of 1977, and the Powerplant and Industrial Fuel Use Act of 1978.
- To assess, by geographic regions, the consequences of using coal in industrial boilers.
- To identify and analyze other constraints to the use of solid coal in industrial boilers (including such factors as space requirements, economics, convenience, industry attitudes, solid waste production, and resource requirements).
- To compare alternative coal-fired boiler technologies.

SCOPE OF STUDY AND SOME SIGNIFICANT FINDINGS

The conclusions of the CTA's study are based on a comparison of five technologies in terms of assumed coal use from now to the year 2000. The five technologies were selected after being identified by appropriate experts as likely candidates for burning coal in industrial boilers. Estimated rates of market penetration for the five technologies were obtained from the same experts. The technologies, which are described in Chapter 6, are: conventional combustion in a spreader-stoker boiler, conventional combustion with a flue-gas desulfurization (FGD) system, fluidized-bed combustion (FBC), low-Btu gasification, and physical coal cleaning (alone and in combination with the above technologies).

An historical overview is the topic of Chapter 2. Many of the factors that now constrain coal use in industry have historical precedents. Literature of the late 19th and early 20th centuries testifies to the difficulties in handling coal in industrial uses, and while coal had become the predominant fuel in the U.S. by the early 20th century, its decline was precipitous when alternative fuels became available.

For example, coal use in industry (excluding coking coal) has fallen from about 40 percent of total industrial energy use to about 6 percent within the last thirty years. The decline cannot be attributed strictly to the lower fuel prices for oil and natural gas; additional factors such as efficiency, convenience, reliability of supply, increased productivity from electrification, and certainly, cleanliness, were important considerations.

Furthermore, historical accounts indicate that the concern over air pollution as a result of burning coal is not a recent phenomenon. Air quality concerns date back for centuries. We note that periods of improving air quality are accompanied by public reluctance to accept additional pollution. The significance of this reluctance should not be overlooked when the return to an inherently dirtier fuel is being widely advocated.

The legislative context in which increased use of coal in boilers must be placed is treated in Chapter 3. Major environmental acts including the Clean Air Act and Amendments of 1977 and the Resource Conservation and Recovery Act of 1976 are summarized, as well as the energy policy legislation of the Power Plant and Industrial Fuel Use Act of 1978 and the National Gas Policy Act of 1978. In the nexus of these four pieces of legislation, we begin to see the complexities inherent in balancing energy and environmental imperatives. The latter two acts, which are both part of the National Energy Act, represent two different approaches to increasing coal use in industry and, as such, are crucial to our understanding of present legislative thinking on how industry can help steer the nation through its current energy dilemma.

Chapter 4 offers a comprehensive survey of literature on the technical and logistical problems in installing new coal capacity, especially at existing plants. Such factors include transportation, space limitations, boiler derating under conversion to coal, and operation and maintenance requirements. Three-quarters of the coal used in the U.S. in 1976 was moved by rail, but rolling stock and road beds are deteriorating. The municipal location of most industry means that space is at a premium, and the land requirements for coal storage, handling, possible pollution control equipment, and subsequent waste disposal place coal at a disadvantage compared with oil or natural gas. Converting existing oil- or natural-gas-fired boilers to coal would result in a steam derating of 50 to 70 percent at a cost approaching that of a new boiler. Coal boilers have capital costs two to five times greater than those using other fossil fuels. Such considerations suggest the direct use of coal is generally feasible only in boilers producing at least 100,000 lb of steam per hour; that is, the class of large industrial boilers. Indeed, over 99 percent of some 6000 boilers identified for coal conversion under the Fuel Use Act have been granted exemptions from using coal. Based on these factors, knowledgeable industry analysts are quite pessimistic about the prospects for coal conversion. Many, in fact, view the future supply and price of coal as no more reliable than that of natural gas or oil.

The current role of boilers in industry is outlined in Chapter 5, including the most recent estimates of how energy is used by various industries, with which fuels, and with what technologies. Regional distribution of boilers and energy use is presented. The aggregate national figures, by themselves, may be misleading and an inadequate basis for the formulation of policies. Sufficient detail is provided in order to reflect the very heterogeneous picture industry presents with respect to energy usage. For example, slightly over 60 percent of total industrial energy consumption in the U.S. occurs in ten states. Further, four key industry groups account for 60 percent of industrial energy consumption; the same industries account for over 70 percent of the fuel burned in industrial boilers. Not only are industries concentrated regionally, but 60 percent, on the basis of fuel use, are also located in municipal areas. Existing industries rely predominantly on natural gas (67 percent by fuel use), though regionally the percentages vary from 85 to 3 percent. And some regions still remain heavy users of coal in industry--over 50 percent in some cases. Finally, a little more than one percent of the large boilers in industry account for over 40 percent of capacity. Sensitivity to such factors is essential in assessing the impacts of increasing the use of coal in industrial boilers. But data for a complete picture are lacking, particularly for the small boiler sizes that are uneconomical for most coal use.

Chapter 6 describes the five technologies under investigation and establishes the methodological framework of the analysis. Units delivering 100,000 lb of steam per hour, approximately the average size of industrial units based on energy consumed, were used as the standards for comparison. "Typical" Eastern and Western coals were also identified. The level of demand projected for the year 2000 is 6 Q. (6 Q would equal about 252 million tons of coal, or about 5.5 times current industrial use of coal in boilers, representing a 7.2 percent increase per annum in the growth of coal use.) This is a high, but justifiable, assumption; it represents the intent of the Fuel Use Act, and would result from the burning of coal in about 75 percent of all new boilers. Whether American industry can actually increase coal use to such an extent is tested, in part, by the analysis in the remaining chapters. From a technical standpoint, physical coal cleaning is the most generally applicable of the technologies compared.

Certainly one of the most serious concerns relating to a widespread resurgence of the use of coal in industrial boilers is the potential for deteriorating air quality, the subject of Chapters 7 and 8. [illegible] the historical support for [illegible] air quality regulations [illegible] limit the use of coal.

Chapter 7 focuses upon the national and regional impacts a widespread shift to coal in industrial boilers would entail. From the perspective of air quality, natural gas, closely followed by distillate oil, is the most ideal fuel for industrial boilers. At the year 2000 coal-use levels noted above, sulfur dioxide (SO_2) emissions would increase to 7.5 million tons per year, or about half of present sulfur dioxide emissions from the electric utility industry. Nationally, regions that now contain much industry and rely on natural gas, as exemplified by the Gulf Coast states, would experience the largest percentage and absolute increases in sulfur dioxide and total suspended particulate (TSP) levels. And almost all regions would experience deteriorating air quality, if other sources of air emissions were not cleaned up sufficiently to counterbalance the emissions from coal-fired industrial boilers.

Analysis presented in Chapter 8 suggests that a 6 Q level of coal use in industrial boilers may never be attained. First, a detailed analysis of half of present boiler capacity (located in seven states) indicates that 65 to 70 percent of industrial facilities are located in "dirty air" non-attainment areas. Obtaining permits for coal-fired boilers there may be difficult because of an apparent unwillingness of existing industries to trade their own potential to reduce emissions to industries that may compete with them. Furthermore, two-thirds of nationwide emissions from industrial boilers occur in municipal areas. This concentration makes industries highly visible and subject to local opposition, should air quality be perceived to worsen. In all likelihood, the middle-sized industries are the most susceptible to such opposition.

Chapter 9 addresses the resource requirements and solid waste burdens of the candidate coal technologies and for the assumed year 2000 coal-use level. Comprehensive pictures of the entire fuel cycle, from mining the coal to producing the steam, are presented. We discover that conventional combustion requires the fewest resources (except for water in the case of fluidized-bed combustion), and that low-Btu gasification requires the most. Overall, the largest resource impact for the assumed year 2000 coal-use level would be a 40 percent increase in mined coal requirements over present domestic production. Additional water and land requirements would come to approximately one percent of present demands. Solid waste generation would markedly increase, with states along the Gulf Coast and Great Lakes bearing the largest burden. In fact, 95 percent of the possible 50 to 75 million additional tons of solid waste would be generated in the central U.S. Compounding such increases is the fact that two-thirds of the waste would require disposal near municipal areas, resulting in an increase of 10 to 30 percent over the present amounts of disposed municipal wastes. Furthermore, much of the waste will be generated by industries that do not have experience in large volume waste disposal.

Chapter 10 provides an economic analysis of coal use. Comparisons between alternative coal technologies indicate that fluidized-bed combustion is slightly less costly than flue-gas desulfurization on a conventional boiler, though both are more expensive than conventional combustion alone. The use of cleaned coal increases the cost of steam only marginally in both conventional and advanced coal-fired boilers. Capital costs for low-Btu gasification systems are nearly 50 percent higher than for a conventional boiler alone, and 25 percent higher than one equipped with flue-gas desulfurization equipment.

Sensitivity analysis identifies the extent to which the cost of steam from coal-fired boilers is influenced by boiler size, load factors, capital charges, and other operational variables. The economies of scale associated with coal-capable technologies are clearly demonstrated. These sensitivities are compared and contrasted with gas-fired boilers. Because of the higher capital costs of coal technologies, the use of coal is, in general, only cost-effective in large boilers that operate at high load factors.

Based upon case studies of specific industries, coal use appears most economical for energy-intensive industries, such as petroleum refining and primary metals, that are located in relatively close proximity to suitable coal supplies. In large energy-intensive industries located predominantly in the Gulf Coast region (chemicals and primary aluminum plants, for instance), a conversion to coal is less likely to be perceived as a cost-effective strategy in the near term. For smaller, less energy-intensive firms, the capital requirements of installing coal-capable boilers are unlikely to be justified, regardless of regional location. For all companies, however, a shift to coal may pose unattractive opportunity costs.

The concentrated and municipal nature of industry, plus the greater environmental risks from coal use in industry, suggest that withdrawing the use of natural gas should be reconsidered. Furthermore, recent trends in industry accentuate the importance and potential of conservation. The use of coal can make sense. But if coal use is to be accepted, intense study must be focused on where coal can be accommodated in the nation's energy economy. These and other topics are the subject of Chapter 11.

Finally, an interview campaign was arranged with plant managers from various industries around the country. The individual contacts touched on many of the issues addressed throughout the report. A full account of the interview effort is offered in Appendix A. A number of additional appendices provide further details on the technologies investigated and the methodologies employed.

The major historical problems with coal are the same ones we meet now: how to burn significant amounts of coal cleanly, how to maintain a dependable supply, and how to handle the additional environmental burdens of coal as compared with alternative fuels. Our study explores the possibilities for industry in sufficient depth to provide further important problems for analysis.

A NOTE ON THE REGIONAL CONFIGURATION USED

Figure 1 displays the regional configuration used in this report and throughout the Coal Technology Assessment program. Different in many respects from more familiar regional breakdowns, such as those used by the Bureau of the Census, the Department of Energy, and the Environmental Protection Agency, the CTA configuration presents regional breakdowns that are consistent in terms of energy usage. Such consistency highlights differences in impacts from the use of coal.

The selection of the CTA regional configuration is based largely on the following four factors: (1) predominant uses of fuels in the major energy-consuming end use sectors (industry, residential, commercial, transportation); (2) predominance of primary fuels used in electricity generation; (3) regional distribution of major energy-consuming industries by two-digit Standard Industrial Classification (SIC) codes; and (4) regional locations of major coal deposits.

Any such configuration is arbitrary, to a certain degree. However, as an accounting device that allows cross-sectoral and inter-regional comparisons, we have found the CTA regional configuration to be superior to those in more common use.

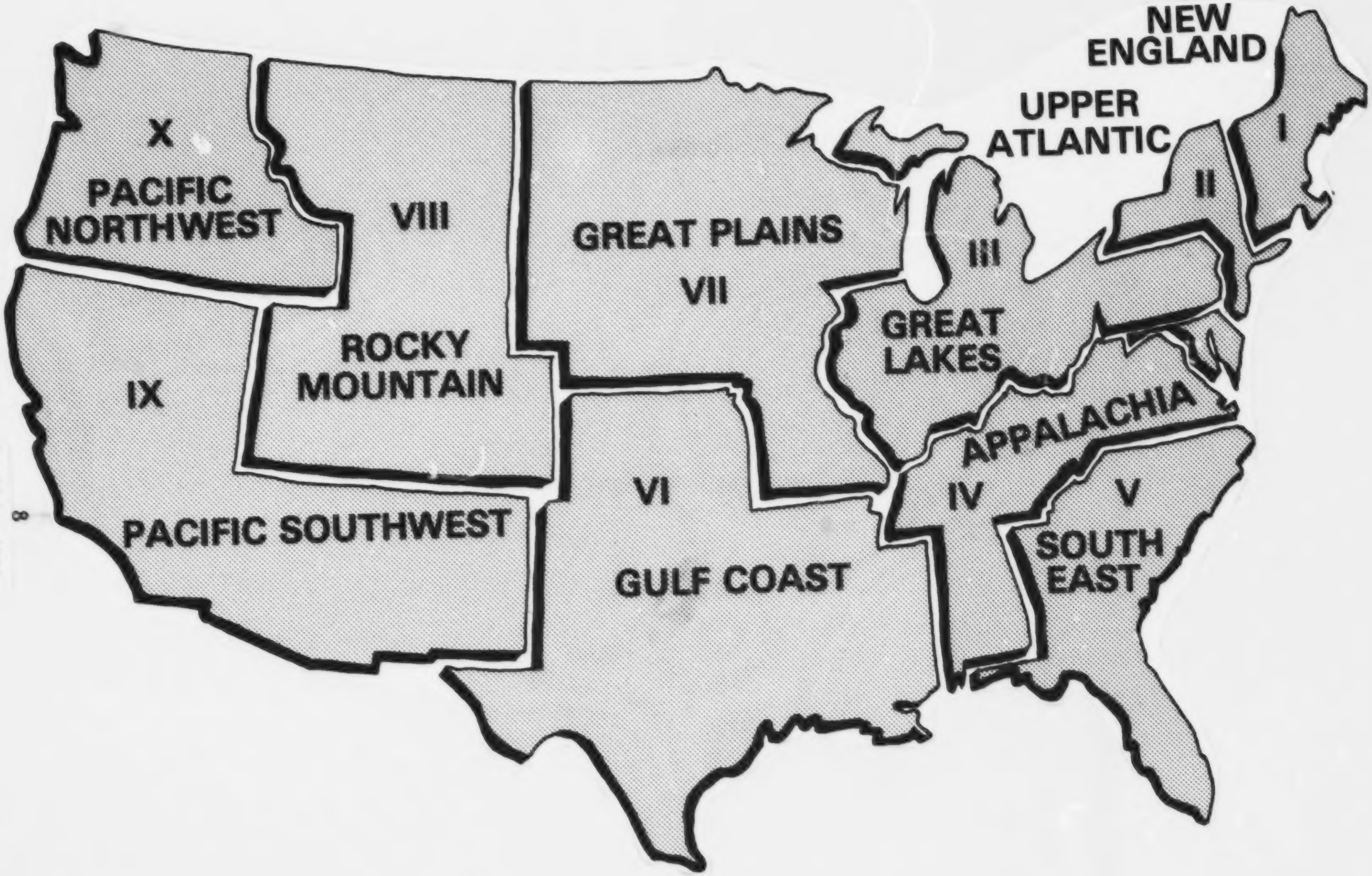
NEW ENGLAND
I
UPPER ATLANTIC
II
III
GREAT LAKES
APPALACHIA
IV
V
SOUTH EAST
GREAT PLAINS
VII
VI
GULF COAST
X
PACIFIC NORTHWEST
VIII
ROCKY MOUNTAIN
IX
PACIFIC SOUTHWEST

Figure 1. Coal Technology Assessment (CTA) regions.

CHAPTER 2

HISTORICAL OVERVIEW OF INDUSTRIAL USE OF COAL

At one time, coal dominated the energy economy of the United States. The rise in coal use was dramatic, as was its subsequent decline. Figure 2 portrays historical trends in U.S. fuel use. Coal, which accounted for nearly 80 percent of the nation's energy needs in 1915, was contributing only 20 percent five decades later. The decline is particularly significant when one considers that from 1947 to 1974 the amount of coal consumed for electricity generation more than quadrupled, and coal's proportional share of the utility fuel market remained relatively constant at about 50 percent (1). Thus,

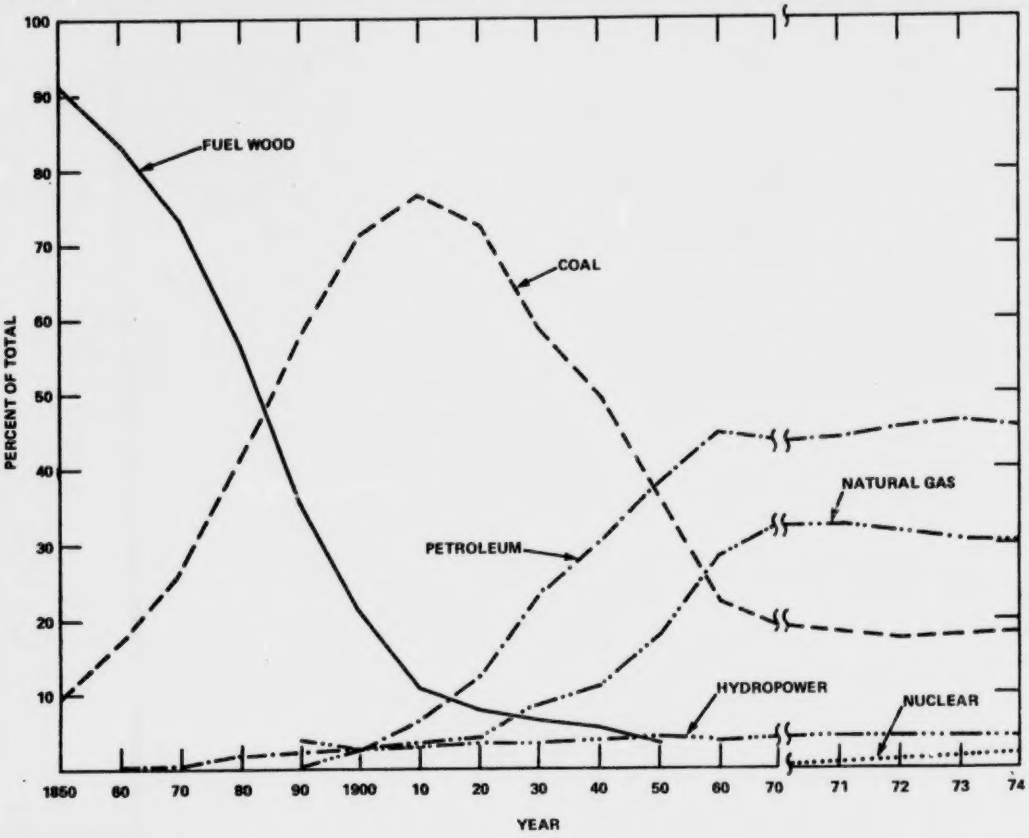

Figure 2. Historical trends in total U.S. fuel use (2).

the substantial shift away from coal occurred in the residential/ commercial, transportation, and the industrial sectors.

The histories of coal and of steam are closely intertwined. Abundant supplies of coal in both England and America fueled the steam engines and boilers that sparked the rapid industrialization of the 18th and 19th centuries. Concomitantly, it was the continuous development and refinement of steam technology that led to the eventual supremacy of coal as an energy source for a rapidly expanding industrial economy. Current patterns of industrial development in America still reflect the past influences of steam and coal. Yet many of the factors that may constrain a greatly expanded use of coal in the future also have roots in the past.

DEVELOPMENTS IN BOILER TECHNOLOGY

The earliest description of a steam boiler was published nearly two thousand years ago by the mathematician and inventor, Hero of Alexandria (3). As it was in Hero's time, steam technology remained little more than a curiosity throughout the ensuing sixteen centuries. Although significant theoretical and technical progress was made during the 17th century, it was not until the introduction of the Newcomen engine in 1712 that steam was employed to provide useful mechanical power. The earliest applications of steam engines in England were for pumping water from coal and tin mines. Similarly, the first installation in America was erected in 1777 to pump water from the Schuyler copper mine near Passaic, New Jersey (4). As is true with perhaps all innovative technology, the first commercially successful application of steam technology stimulated rapid advances in design and performance. James Watt, working with Matthew Boulton, made a series of important improvements on the Newcomen engine. Watt's innovations included the addition of a separate condenser, conversion of reciprocating motion to rotary motion, introduction of two cylinders, and development of the double-acting engine in which steam is applied to both sides of the piston. Each of these innovations dramatically increased the power and efficiency, as well as the usefulness, of steam engines.

In America, the impetus behind early attempts to refine steam technology was provided by the need to improve transportation. Although the quest, led by John Fitch, to perfect a steam-powered ship was not entirely successful, it did result in the diffusion of steam technology. For example, in 1792, William Longstreet, who had been actively engaged in steamboat enterprises, announced the invention of a steam engine designed to turn sawmills and gristmills (4). A number of these engines were installed throughout the southern United States.

The steam boiler and engine industry reached maturity with the rapid growth of Pittsburgh in the early 19th century. By 1810, extensive ironworks had been established in Pittsburgh, attracting prospective boiler and engine manufacturers. In fact, the iron industry and the steam industry were often inseparable. Such notable engine builders as Oliver Evans, Benjamin Latrobe, and Robert Fulton located their businesses in Pittsburgh.

The early 19th century was characterized by rapid improvements in boiler design and performance. Oliver Evans introduced the first fire-tube boiler between 1804 and 1810. This innovation greatly expanded the heating surface area and thereby accomplished huge improvements in efficiency and power (5). Multitubular arrangements soon followed, beginning with the Lancashire boiler in 1834 and culminating with the return flue, "Scotch" or "marine," boilers. Although not extensively used until the end of the century, water-tube boilers capable of producing high pressure steam became available with the introduction of the Babcock and Wilcox boiler in 1838 (6). At that time, there were 1860 stationary steam boilers operating throughout the United States, finding applications in every form of manufacturing enterprise (4).

From the middle of the 19th to the early 20th century emphasis was placed upon adapting steam technology to transportation. Such designs emphasized reducing boiler size while gaining power, efficiency, and ease of operation. The latter half of the 19th century witnessed the construction of the Great Eastern steamship, steam-powered cranes, harvesters, and steamrollers; the infamous London to Edinburgh train races; and finally in 1900, the introduction of the "Stanley Steamer" automobile. The quest for reduced size and greater ease of operation continued into the 20th century. In the mid-thirties the Babcock and Wilcox Company offered their Integral Furnace Boiler, a prototype of the small, highly efficient, "packaged" boilers that gained widespread acceptance after World War II (5).

IMPACTS ON INDUSTRIAL GROWTH

The continuous development and refinement of the steam engine had a number of profound impacts on American industry. Prior to the development of steam technology, industry could locate only where water power was available. As the best sites were taken first, new industries or expansions of existing industries could only be accommodated in areas increasingly remote from centers of population and transportation. To the west of the Appalachian mountains, shortages of adequate motive power were severe. Very few streams possessed the hydraulic head required by mills and other manufacturing establishments. This shortage of power posed a serious constraint on further westward migration and industrialization. Reliance on water power had two other negative aspects. First, economies of scale frequently could not be attained because of the limitations imposed by the capacity of stream flows. Second, productivity was curtailed because a consistent power supply was not available; streams had the tendency to freeze in the winter, flood in the spring, dry up in the summer, and become clogged with leaves during the fall (4).

With the increasing availability and reliability of steam technologies in the early 19th century, manufacturing establishments were free to locate in close proximity to labor supplies, raw materials, markets, and transportation centers. Large manufacturing establishments became possible, and with them the economic efficiency attendant to scale. The centralization of industry, which was fostered by steam engines, had the immediate effect of raising productivity and lowering costs. Steam technology benefited small enterprises as well. Shops were opened that "rented" fractions of the power from large, centrally located, steam engines. Small engines could also be used in enterprises that previously would have been too modest to afford even the smallest of available stream sites. Clearly, steam technology allowed industrialization to become more than a limited urban phenomenon. Steam technology was directly responsible for the attainment of economies of scale, centralization, the proliferation of many competing industries, the growth of small specialty shops, and the rapid expansion in industrial capacities, all of which provided the key to dramatic and revolutionary increases in productivity and economic efficiency.

ADVANTAGES OF STEAM HEATING

Although most of the early developments in steam technology were directed toward providing mechanical power, the use of steam to provide heat to industrial processes also gained acceptance during the Industrial Revolution (7). Substantial amounts of heat were required in a variety of industries and processing operations. In the textile industries, large quantities of fuel were burned to heat liquids used for scouring, bleaching, dyeing, and printing cotton and wool fabrics. Additional heat was employed for combing, drying, and pressing fabric materials. In the chemical industry, heat was required in the evaporation of salt and alum as well as in the production of soap. Breweries and the sugar industry had large demands for fuel to heat water. Prior to the introduction of steam, heat was applied directly by open coal or wood fires located under processing vessels. Heating by steam offered numerous and distinct advantages. Since individual fires no longer needed to be ignited and subsequently extinguished for each heating operation, 50 to 70 percent of the fuel consumed by direct heating techniques could be saved. Increases in the efficiency of fuel consumption lowered costs, especially for manufacturers located far away from coal fields.

Another cost reduction that was gained as a consequence of using steam was in the capital cost of processing equipment. Since the heat, when steam was used, was applied to the material to be heated rather than to the vessel containing the material, vats, kettles, evaporators, and other processing equipment could be constructed from thinner, less expensive, metals.

Costs for labor and maintenance--such as lighting and monitoring fires, handling fuel, cleaning residues--could be reduced by employing steam heating technologies. The use of steam also afforded much better temperature control. Closer control of temperature prevented the burning or scalding of products and thus raised productivity while simultaneously enhancing the quality of many manufactured goods. Heating materials with steam could generally be accomplished more rapidly than heating them with open fires. By circulating high temperature steam through tubes immersed in process vessels, or simply by injecting steam into the liquid to be heated, one could greatly enlarge the surface area exposed to heat. Faster operation allowed productivity to increase. Finally, the substitution of steam for open fires markedly improved the cleanliness of processing operations. Cleanliness was extremely important in the textile industry because the smoke and dirt released from open coal fires could permanently damage fabrics.

EFFECT ON FUEL CONSUMPTION

As the use of steam technologies expanded, so did the demand for fuel. Wood, which had been the dominant fuel in America, was gradually becoming scarce. Although the wood shortages in America were never as acute as they were in Europe, supplies near cities and towns had diminished and local shortages were not uncommon (8). By the middle 1800s, coal was widely used as a heating fuel. The use of coal as a boiler fuel was encouraged by several factors. Efficient steam raising required a fuel that could provide a high temperature flame and carried a maximum Btu content per unit volume. Coal was superior compared with wood in both respects. In addition, most boiler manufacturing establishments were integrated with iron foundries where coal was already commonly used in smelting processes. The combination of experience in using coal, and its local availability, ensured that most boilers would be designed to burn coal.

Soon after the turn of the century, coal consumption had become nearly synonymous with total energy use. In 1918, over 600 million tons of coal were produced providing 17.0 quadrillion Btu of available energy. Although by the beginning of the 20th century, coal had become the predominant fuel of industry, as it was in all energy-consuming sectors, the shift away from coal was precipitous. For, as the amount of coal mined and consumed rapidly expanded after 1900, and the rate of that expansion continued to accelerate over the next few decades, the infrastructural capacity necessary to support a coal-based energy economy became overloaded, faltered, and signaled the beginning of the shift away from coal that has characterized industrial energy consumption ever since. The reasons for the decline of coal as an industrial fuel were the growing difficulties in transporting coal, uncertainty and unreliability of supplies generally, the inconvenience of using coal at industrial sites, continuing advances in boiler design, the availability of preferred fuels, and finally, public initiatives directed toward improving the quality of the nation's air.

PROBLEMS OF COAL TRANSPORTATION AND SUPPLY

As early as 1850, an observer from England noted that American manufacturers were unable to obtain the quantities of coal they would "willingly take" and that actual coal use was, perhaps, only one-third of demand because there was "no certainty of a continuous supply" (7). The lack of certainty was mostly due to deficiencies in America's transportation facilities. In 19th century rural America, overland transportation of any bulk commodity was difficult and expensive. The rapid growth of electric power near the turn of the century was, in part, a result of the greater ease in delivering electricity to the widely dispersed markets that characterized America at that time.

In the first quarter of the 20th century, as the demand for and dependence upon coal increased, and energy markets became even more dispersed, the costs and logistic difficulties of transporting coal from producing to consuming regions became quite severe. Railroad companies could not economically maintain enough rolling stock to transport coal during periods of peak demand

(9). Thus, from September through March, coal was intermittently in short supply. Maintaining a continuous supply of coal to industrial sites was further impeded by the congestion that was typical at terminals and switching yards (10). These two factors, lack of adequate transportation capacity and widespread congestion during periods of peak demand, led to serious coal shortages in 1916, 1918, 1922, and numerous temporary supply interruptions (11).

Wholesale and retail dealers used lack of transportation as an excuse to abrogate contracts. Coal that had, in fact, been previously contracted was placed on the spot market where prices were considerably higher (12). Dealers were able to reap huge profits in such a manner since the average profit margin on contracted coal was eight percent, while for spot market coal it was 25 percent (13).

Compounding the problem was the fact that mines would cease operations whenever trains were unavailable for transporting the coal to consumers. Coal could not be economically stored at the mine because storage required that coal be handled twice--nearly doubling the cost of the production. Stored coal deteriorated in heating value, resulting in a poorer quality of coal at a higher price (14). Cessation of mining operations tended to escalate coal prices anyway, since production costs always rise as the working time of mines decreases. Thus, transportation shortages led to temporary mine closings, which in turn led to further labor unrest, generally higher prices, and precipitated future discontinuities in the coal marketing and supply infrastructure.

Concurrently, costs of transporting coal rose sharply. Even during the height of industrial coal consumption, between 1915 and 1927, transportation charges constituted the chief element in the price of coal delivered to factories and retailers (15). Freight rates were blamed for leading to a paralysis of manufacturing plants and were considered the prime contributor to an inflationary economy (15). Although complete data prior to 1936 are unavailable, Table 1 provides an indication of annual levels of coal transportation costs. Prior to 1942, when price controls were imposed, the cost of transporting coal was greater than the cost of producing it; transportation costs never comprised less than half of the mining costs. Price increases continued upward at a slower pace after World War II, owing to the declining demand for coal.

Besides the fact that the railroads maintained a virtual monopoly on coal transportation in a high demand market, freight rates were high because of the inefficient way in which coal was contracted and marketed to industrial consumers. Factories generally purchased coal from a number of small mines. Arrangements had to be made for small shipments of coal from a number of locations rather than a larger shipment of coal from a single location. Such a situation prevented the railroads from ever achieving the most efficient allocation of available rolling stock. Inefficient allocation of resources raised costs to the railroad companies, thereby increasing prices to consumers. As the industrial economy expanded, the coal transportation and supply infrastructure became ever more fragmented and inefficient. Lack of

TABLE 1. AVERAGE RAIL REVENUE PER TON OF BITUMINOUS COAL HAULED (AS PERCENTAGE OF AVERAGE MINED VALUE) (8)

Year	Average value per ton, f.o.b. mine ($)	Average revenue per ton hauled on Class I railroads	Revenue/ value (%)
1959	4.86	$3.57	73.4
1958	4.86	3.58	73.7
1957	5.08	3.57	70.3
1956	4.82	3.45	71.6
1955	4.49	3.24	72.2
1954	4.51	3.23	71.6
1953	4.92	3.33	67.7
1952	4.90	3.35	68.4
1951	4.92	3.16	64.2
1950	4.84	3.09	63.8
1949	4.88	3.00	61.5
1948	4.99	2.74	54.9
1947	4.16	2.49	59.8
1946	3.44	2.27	66.0
1945	3.06	2.20	71.9
1944	2.92	2.21	75.7
1943	2.69	2.30	85.5
1942	2.36	2.31	97.9
1941	2.19	2.22	101.4
1940	1.91	2.22	116.2
1939	1.84	2.23	121.2
1938	1.95	2.27	116.4
1937	1.94	2.17	111.8
1936	1.83	2.25	123.0

adequate transportation capacity, and the associated supply problems arising from it, became so serious and controversial that legislation was introduced on the Senate floor in 1920 that would have led to the nationalization of the coal mining and transportation industries (16).

Besides the major transportation problems that accompanied the use of coal as a primary fuel, there were other minor, but eventually serious, problems that were intensified by the rapid growth of the industrial economy. The variety of coals appearing on the market made quality assurance, and hence boiler operations, more difficult. Inclement weather often disrupted coal supplies for extended periods and made on-site coal handling problematic.

Labor unrest at the mines also increased uncertainty over supplies. Acute coal shortages resulting from miner strikes occurred in 1919, 1922, and, to a lesser extent, in 1927. Expansions in plant capacity, which were already impeded by the predominantly urban location of industry, were further constrained by the significant amount of space necessary for coal handling and storage facilities. As oil became available, its greater efficiency and the savings it afforded in storage space and labor costs mitigated even further against the continuing use of coal (7). Natural gas also began to be used widely as an industrial fuel, accounting for eight percent of total industrial energy consumption in 1920 and 18 percent by 1940. Electric motors also displaced a significant portion of on-site coal use within manufacturing establishments. Purchased electricity, which contributed only 11 percent of primary horsepower in 1905, provided 61 percent of the total mechanical power employed in the industrial sector by 1927 (10). The higher cost of electric power was offset by its greater convenience. The factors contributing to the rapid decline of coal as an industrial fuel were identical to those responsible for its decline in the residential and commercial sectors (17).

A variety of technological developments served to accelerate the switch away from coal in the industrial sector. The spread of mechanized mining techniques had two major impacts. As more capital was substituted for labor, the average size of mines increased and nearly continuous operations were necessary to achieve the large production volumes that were required to amortize large capital investments (10). In order to maintain maximal efficiency, mine owners provided fewer long-term contracts to small and dispersed consumers. As a result, an ever increasing percentage of manufacturing establishments were forced to purchase coal on the spot market at a significantly higher price and on a much less reliable basis (13). Moreover, advances in boiler technology had a profound effect upon fuel selection. For many years the focus of technical development had been on reducing size while raising efficiency. Reductions in boiler size not only lowered space requirements, but allowed boilers to be shipped fully constructed, as a single package, which substantially lowered capital and installation costs. The goal of compact and efficient boilers, however, was only attained by utilizing exceedingly small diameter water tubes at high density spacing. To prevent damage, operators burned only clean fuels, such as natural gas and oil, in packaged boilers. Therefore, the rapid deployment of these boilers throughout the industrial sector after World War II stimulated a commensurate decline in coal combustion.

Figure 3 demonstrates the decline of coal use by industrial firms from 1947 to 1976 (sector breakdowns are not available prior to 1947) (1). While coal (excluding coking coal) provided nearly 37 percent of industrial energy requirements in 1947, coal accounted for only six percent by 1976. Although total industrial energy consumption rose dramatically over this time frame, coal consumption decreased at a relatively constant rate.

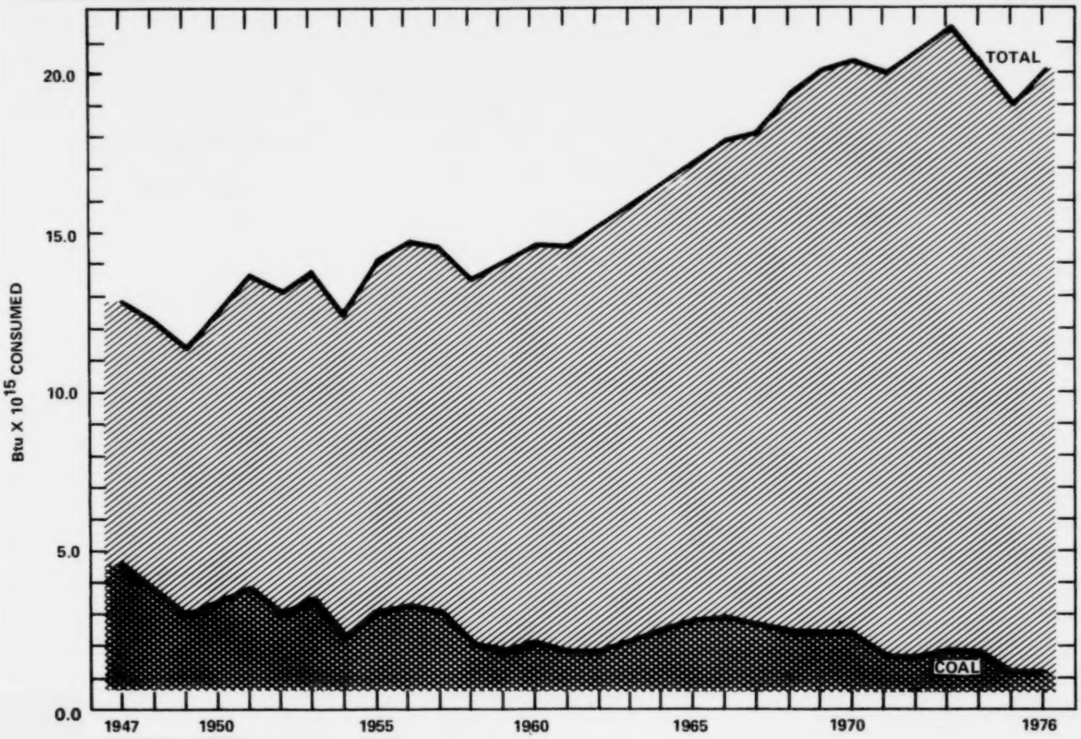

Figure 3. Industrial coal consumption compared with total industrial fuel use (excludes coking coal).

ROLE OF FUEL COSTS

Because adequate data are not available, it is difficult to assess the extent to which fuel costs contributed to the rapid decline of coal use in the industrial sector. Certainly, from the end of World War II to the oil embargo in 1973, plentiful supplies of cheap natural gas and oil were available. Yet, before that time some evidence suggests that differentials in fuel prices were only partially responsible for the shift to oil and gas. For example, electricity quickly displaced coal-gas as the preferred means of illumination, even though for most consumers it was the more expensive alternative. Electricity offered distinct advantages in terms of convenience. Replacement of coal by oil in the railroad industry, which for many years was the largest consumer of coal, was clearly motivated by the increased efficiency, decreased maintenance, and ease of handling, rather than by relative fuel costs (which were much lower for coal) (7). Even before the major disruptions in the coal industry that characterized the 1920s and prior to the ascendency of packaged boilers in the 1940s, the operational advantages of gas and oil--such as ease of handling and storing, cleanliness, and temperature control--were considered significant enough to justify the use of gas and oil regardless of the additional costs. The availability of gas and oil was the most influential factor in determining consumption. If gas and oil could be had, operators would use these fuels, even if their prices were higher than coal (18). As reported in 1903, for example, the Republic Iron and Steel Company of Alexandria, Indiana, engaged in the "curious spectacle" of hauling coal three miles from the factory to a natural gas compressing station where the coal was burned to generate power to pump gas back to the factory, all for the sake of "convenience of gas in operating the steel mill" (19). Similarly, the National Industrial Conference Board noted in a report in 1931 that the appeal of natural gas and oil was based more upon their convenience than upon their lower cost (10). Charles Berg, in a thorough analysis of industrial fuel use from the 18th to the 20th century, offers further evidence that suggests fuel costs play a secondary role in fuel choice decisions (20). According to Berg, within the industrial sector, cost considerations have historically tended to have a greater influence upon fuel utilization methods, and on the technical design of production process, than on the choice of the fuel itself. The expected utility of the fuel in satisfying various operational imperatives is, perhaps, of greater importance in fuel selection by industrial firms.

AIR QUALITY CONSIDERATIONS

The final influences in the string of events leading to the nearly complete abandonment of coal use in the industrial sector were public initiatives directed toward improving the quality of the nation's air. Contrary to common wisdom, an awareness of the tension between burning coal while simultaneously maintaining the quality of the physical and human environment is not a recent phenomenon. Indeed, the first written account of that awareness extends back over two millenia to Theophrastus, a pupil of Aristotle, who noted that when coal is burned the "smell is troublesome and disagreeable" (21). The consistent misperception that associates the beginning of environmental problems, especially air pollution, with modern levels of industrial activity is probably less the result of absolute pollution levels than the changing perceptions of environmental quality that have accompanied the evolution of industrial economies.

The gradual emergence of industry in Britain was continually interspersed with conflicts between the utilization of coal and the degradation of air quality. In the last quarter of the 13th century, smoke from coal combustion had already become a serious nuisance in London. The predominant fear in the 13th century was that coal smoke would have a deleterious effect upon one's health (22). Royal commissions of inquiry were appointed in 1285 and 1288 to investigate complaints about emissions from coal-fired lime kilns (23). These investigations failed to devise a solution to the pollution problem; instead, in 1307, a ban on coal use was imposed by King Edward I (23). The ban was, perhaps, never totally effective, since cycles of plague later decimated the population to a point that allowed the much preferred fuels of wood and charcoal to regain their original preeminence (22).

Pressure to use coal remained at a low level until the second half of the 16th century. When the population returned to pre-plague levels between 1580 and 1680, however, the importation of coal into London increased twenty-fold. Commensurate with such an increase, complaints about air pollution became quite frequent (22). The burning of coal was banned in breweries near Westminster. Charles I, in 1638, forbade the importation of coal into London from Newcastle. The first serious work on air pollution, John Evelyn's Fumifugium: or the Inconvenience of Air and Smoke of London Dissipated, published in 1661, noted the damage coal smoke inflicted upon buildings, vegetation, and people (24). Evelyn emphasized the contribution of industrial sources to pollution levels--even though at the time, emissions from residential sources were probably greater than or equal to those from industrial sources. He suggested that industrial plants be compelled to locate far from urban areas and be surrounded by parks or other plantings (25). Evelyn's book was followed by the publication of John Graunt's Natural and Political Observations upon the Bills of Mortality, the first statistical examination of the health effects of polluted air (26). Graunt attributed London's high mortality rate primarily to the pollution arising from the combustion of coal. Yet, by the middle of the 17th century, London had become the world's foremost industrial center. The city was, by then, nearly totally dependent upon coal. Because no replacement fuels were available, banning the use of coal in London's countless factories and workshops and thousands of domestic fireplaces would have brought certain economic collapse, and, therefore, ceased to be a legitimate strategy for controlling pollution.

Nonetheless, the works of Evelyn and Graunt stimulated the Royal Society to conduct a wide range of investigations into the modes of air pollution, the means by which pollution damaged health and materials, and the interaction of various weather conditions and high emission levels. Throughout the 1700s, techniques were developed to allow identification of the major elements in air pollution, including sulfur dioxide. Scientists noting dead and dying vegetation near industrial sources began to study the chemistry of precipitation. Physicians commonly prescribed a stay in the cleaner air of the country for patients suffering from respiratory diseases.

In spite of a growing knowledge of the damage caused by air pollution, the use of coal steadily increased over the next hundred years. Air quality continued to deteriorate, becoming a serious problem throughout all of industrialized England. The 1800s and early 1900s were characterized by the introduction of local legislation intended to control air pollution. Following John Evelyn, 19th century control acts focused on industrial sources, were generally only applicable to "smoke from furnaces and steam engines," and usually endeavored to provide a geographic separation between point sources and population centers (27). Attempts to develop specific technologies for controlling emissions from coal combustion through "scrubbing" were also initiated in the mid-1800s (28). Yet, these smoke abatement measures were relatively ineffective, failing to restrain the ever increasing emissions from coal combustion. For attendant with the rise of coal use and air pollution were the substantial increases in the standard of living and leisure time being gained through industrialization. Pollution control measures were often thwarted because "preventing smoke from steam-raising furnaces might interfere with the interests of manufacturers" (29). It was not until December 1952 when 3500 to 4000 deaths occurred as a result of air pollution over a period of one week in London, that England was able to install effective pollution abatement laws.

The American experience was, in many respects, quite similar. Accompanying the rapid expansion of coal use in the middle of the 19th century was a remarkable decline in the quality of the nation's air. Nowhere were the residues from coal combustion more noticeable than in Pittsburgh. According to one visiting gazetteer in 1841:

> A dense cloud of darkness and smoke . . . visible for some distance before he reaches it, hides the city from his eyes until he is in its midst; and yet, perhaps half of this volume is furnished by household fires, coal being the only fuel of the place. The surface of the houses and streets are so discolored as to defy the cleansing power of water, and the dwellings are preserved in any degree of neatness, only by the unremitting labors of their tenants, in morning and afternoon ablutions. The very soot partakes of the bituminous character of the coal, and falling-color excepted--like snow flakes, fastens on the face and neck, with a tenacity which nothing but the united agency of soap, hot water, and the towel can overcome. Coal and the steam engine are the pervading influence of the place, and over the whole city the seal and impress is--"Great is Vulcan of the Pittsburghers" (4).

Similar, although less intense, air quality problems were emerging in the rapidly growing, coal-dependent cities of the west. Chicago, St. Louis, Cleveland, Cincinnati, and others, all experienced deteriorating air quality as a consequence of an escalating use of coal (30). Even in the much less industrialized south, the emissions from coal-fired steam engines at times impeded their deployment. For example, in Charleston in 1843, steam engines were forbidden within the city limits largely because of smoke emissions (4). Yet, as was the case in England, the perceived improvement in the standard of living associated with industrialization tended to counteract concerns about the possible health effects of the pollution that accompanied industrial growth. The few control measures that were instituted during this period were ineffective and were usually ignored or repealed--as was the case in Charleston in 1848--within a few years. In the face of a widespread belief that progress required industry, industry required steam, and steam required coal, it is not surprising that smoke became a sign of prosperity and that measures to control emissions had limited public support.

A number of factors contributed to the gradual change in public perceptions of air pollution. In 1874, natural gas was discovered near Pittsburgh and assumed a brief, dominant role in the fuel use of that city. By 1889, coal consumption had dropped by nearly seventy percent. Air quality in Pittsburgh improved remarkably. As gas became less available and coal consumption again increased after 1890, however, the public outcry against air pollution was suddenly vehement (21). Several smoke control ordinances were enacted during the period 1892 to 1907. Subsequent to those initiatives, air quality improved although much of this improvement was probably due to the decline in industrial activity witnessed during the financial panic in 1907 (21). Nonetheless, opposition to smoke was growing steadily and more attention was given to the economic as well as psychological impacts of air pollution. Yet, it was not until the explosive increase in industrial production at the beginning of World War II that a sufficient consensus developed in Pittsburgh and other cities to legislate effective smoke abatement measures. The sentiment for cleaner air was dramatically reinforced when, in 1948, a tragic air pollution episode in Donora, Pennsylvania, resulted in the death of twenty persons and the illness of 6000 more.

Although the earliest efforts to reduce emissions from coal combustion were based on increasing combustion efficiency, after World War II the emphasis was placed on switching to cleaner fuels. Trains in Chicago were converted from coal to electricity while those in other cities were replaced by oil-burning diesel engines. The diesel engine also found wide applicability for use on steamships. Manufacturing industries began the shift to small, gas-fired, packaged boilers. Smokeless anthracite coal became the primary fuel in a majority of private residences before being displaced by the natural gas and oil now flowing in abundance through new pipelines from the southwest. Beginning in the late 1950s and culminating with the passage of the Clean Air Act in 1970, strict air quality standards led to the nearly complete abandonment of direct coal combustion in industrial boilers.

The times of most rapid change in air quality have also elicited the most vehement public response, a vehemence that has increased over the centuries with the growth in industrialization and fuel use. The public reaction to air pollution has not always been rational or scientific. Coal has played the central role in fostering an awareness of air pollution, especially air pollution from industrial facilities with their visible smokestacks and plumes.

Whether the burning of coal alone caused the death and sickness experienced during the infamous air pollution episodes of the past hundred years cannot now be proved; but the suspicions remain. If the direct use of coal in industry is to be greatly expanded, these associations will need to be managed, if indeed they can be, or public acceptance will falter or turn into opposition.

Brimblecombe's thesis is that man's perception of the changing environment and his place in it are as important as changes in technology, and that periods of rapid change in air pollution are more important to the perception of air quality than is the absolute level of pollution (22, 26). The periods of rapid change in air quality outlined above--the two changes from wood to coal in Britain, the close of the Natural Gas Era in Pittsburgh, the explosive growth of industry during World War II, the air pollution episodes in London and Donora--were also the periods of greatest public outcry and most serious legislative initiatives.

The worry, of course, is that after our success over the past three decades in improving the quality of the nation's air by increasing the use of clean fuels, a return to coal as the predominant fuel in industrial boilers could be perceived as a step backwards and may be severely constrained by public and private interventions. Owing to the long-standing historical relation between coal use and air pollution, a sudden escalation in the use of coal in industrial boilers may threaten the balance that exists between energy and environmental concerns.

In light of historical precedent, a rapid and widespread conversion from natural gas and oil to coal might be quite difficult to achieve. For in many crucial respects--the concentration of industry in densely populated areas, requirements of transportation and reliable supply, advances in boiler technology, the value of clean air--the imperatives of industrial energy use that have restricted the use of coal in the past, remain substantially unchanged today.

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CHAPTER 3

LEGISLATION CONCERNING THE USE OF COAL IN INDUSTRIAL BOILERS

A number of recent legislative initiatives will act either to enhance or constrain the increased use of coal in industrial boilers. Four such acts are described in this chapter. The first two, the Clean Air Act and Amendments of 1977 (CAA) and the Resource Conservation and Recovery Act of 1976 (RCRA), are based on environmental considerations. As a result, they are administered by the U.S. Environmental Protection Agency. The second two, the Powerplant and Industrial Fuel Use Act of 1978 (FUA) and Natural Gas Policy Act of 1978 (NGPA), are parts of the larger National Energy Act, which is administered by the U.S. Department of Energy. These two acts establish priorities for the use of specific fuels either through pricing mechanisms or mandated fuel use. Even though other pieces of state and federal legislation, notably the Clean Water Act and the Toxic Substances Control Act, may influence the use of coal, the four subject acts are critical to future energy use in industry.

Coal is a "dirty" fuel. Burning coal without pollution control produces larger amounts of sulfur dioxide, total suspended particulates, and nitrogen oxides than does burning oil or natural gas. Furthermore, the burning of coal has been implicated in larger problems, such as acid rain. If procedures are used to prevent air pollution from coal burning, solid wastes are generated. Thus, depending on the process being used to control environmental damage from coal use, both the CAA and the RCRA could constrain the siting of coal-fired industrial boilers, or limit conversions of existing facilities to coal. Currently, natural gas is the most widely used fuel in industrial boilers. The FUA and the NGPA lay the groundwork for de-emphasizing the use of natural gas in industry. In many respects, the intents of the FUA and NGPA on the one hand and the CAA and RCRA on the other seem incompatible. This situation, which is explored in the remainder of this report, should be clarified to insure that our national policy balances energy and environmental concerns.

Of the four acts, the CAA and the FUA appear to be the most important. The Environmental Protection Agency and the Department of Energy, which have the lead responsibility for these two acts, are in the rule-proposal stage, which is a lengthy part of the regulatory process. The CAA takes precedence over the FUA, which includes specific exemptions for cases where provisions of the CAA would be violated. In cases where conformity to the CAA occurs, and other exemptions in the FUA do not apply, industry receives a signal to use coal or alternative fuels.

The real question arising from these four acts is whether, given environmental considerations, industry can achieve the intent of the FUA, which is supported by the changing prices of natural gas under the NGPA. We return to this question in Chapter 11.

CLEAN AIR ACT

The Clean Air Act and Amendments of 1977 augmented the scope of the 1970 Amendments and constitute the primary enabling legislation for regulating air quality in the United States (1). Indeed, according to many analysts, the Clean Air Act and its Amendments are a turning point in the history of environmental legislation. The main thrusts of the CAA are to maintain air quality in areas that already have clean air and to improve air quality in areas that exceed minimum air quality standards. The primary mechanisms for achieving these goals are the use of clean technologies or fuels, control technologies, and siting restrictions. Major aspects of the CAA are presented below (1).

National Ambient Air Quality Standards

National ambient air quality standards (NAAQS) represent ceilings for pollutant concentrations in ambient air, as measured by approved monitoring techniques. In the areas that exceeded the NAAQS when the CAA was passed, the standards are targets toward which "reasonable further progress" must be made in improving ambient air quality. In all other cases, the NAAQS are absolute, maximum ceilings.

Sec. 109 of the CAA specifies both primary standards, which should allow an adequate margin of safety to protect the public health, and secondary standards to protect the public welfare. Welfare is broadly defined to include vegetation, man-made materials, climate, wildlife, and so on. As shown in Table 2, the standards are established for a number of different monitoring periods.

At this time, secondary standards exist only for total suspended particulates (TSP) and sulfur dioxide (SO_2). These secondary standards are more stringent than the primary ones. For those areas with polluted air that exceeds the NAAQS, the statutory language is more precise in defining achievement of the primary standard. The Administrator of EPA is instructed to review (and revise, if appropriate) the NAAQS by 1981 and at five-year intervals thereafter.

Area Designations

Sec. 107 of the CAA sets guidelines for designating areas of the country as being in attainment, non-attainment, or unclassified for the NAAQS. Attainment and non-attainment designations may be revised based upon new information. An unclassified designation means that the air monitoring infor-

TABLE 2. NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Standard		Monitoring period
	Primary	Secondary	
Total suspended particulates (TSP)	75 $\mu g/m^3$	60 $\mu g/m^3$	Annual geometric mean
	250 $\mu g/m^3$*	150 $\mu g/m^3$	Maximum 24-hr level
Sulfur dioxide (SO_2)	80 $\mu g/m^3$ (0.03 ppm)		Annual arithmetic mean
		1,300 $\mu g/m^3$ (0.5 ppm)	Maximum 3-hr level
	365 $\mu g/m^3$		Maximum 24-hr level
Nitrogen dioxide (NO_2)	100 $\mu g/m^3$ (0.05 ppm)	Same	Annual
	250 $\mu g/m^3$ (0.13 ppm)	Same	Maximum 24-hr level

μg = microgram = 10^{-6} gram, or 0.000001 g
*Second highest value in any year.

mation that existed at the time the CAA was enacted was inadequate for initial classification. The act does not specifically establish a timetable for providing information to classify unclassified areas; in the case of carbon monoxide pollution, EPA has used other provisions in the CAA to obtain the necessary information. Area designations are discussed in greater detail in Chapter 8.

New Source Performance Standards

New source performance standards (NSPS) are emission limitations for new "significant sources" or modified sources. NSPS always apply if the source falls within the major source or modified definitions, regardless of where the facility is located. In some instances emission limitations may be more stringent than NSPS.

NSPS are achieved through fuel pre-treatment, use of cleaner fuels, control techniques, or combinations thereof. The NSPS, then, represent "best" systems of continuous emission reductions. In defining "best," EPA must consider the costs, energy requirements, and other health and environmental impacts from the application of control.

In cooperation with industry representatives, EPA is collecting the necessary background information to propose an industrial boiler NSPS in 1981.

Prevention of Significant Deterioration

Prevention of significant deterioration (PSD) is the primary mechanism in the CAA to ensure that future growth does not significantly degrade air quality in areas that are cleaner than the NAAQS. In applying PSD, a step-wise classification scheme is established that allows differential incremental increases in ambient air pollutant concentrations over an initial baseline concentration. The allowable increments for each class are shown in Table 3.

Class I, the most restrictive, allows for very little increase. International parks, national parks, wilderness areas, and memorial parks over a certain size were all placed in Class I. All other areas were placed in Class II, with mechanisms provided in the act for reclassification to Class I or III. There are no Class III areas in the country. Since passage of the CAA, the only reclassifications from Class II to Class I have been a few areas on Indian Reservations. Perhaps the main reason that there have been so few reclassifications is the combination of procedural steps required, including public hearings, comprehensive analyses, and approvals.

For establishing any major source in a PSD area, a number of steps need to be taken. Successfully passing the review process results in the applicant's obtaining a permit to construct, which is required for all major sources and modifications in a PSD area. First, best available control technology (BACT) must always be applied. BACT is determined on a case-by-case basis, and represents the maximum emission reduction achievable through application of control, fuel pre-treatment, process modifications, and so on, taking into account the economic, energy, environmental, and other costs of control. In no instance may BACT be less stringent than NSPS. If the ambient air quality monitoring data for the desired site are inadequate, up to a year of monitoring (at the expense of the applicant) may be required before the permit can be granted. In all cases, mathematical modeling of varying rigor will be required. The models test how much of the allowable incremental increase will be consumed by the new source. If the model of the proposed site indicates a violation of the increment ceiling, an alternate site must be tested. Even if the increment ceiling is not exceeded, a new source may not be allowed if, in the judgment of the appropriate air quality agency, a disproportionate share of the increment would be taken.

PSD applies in unclassified as well as attainment NAAQS areas (2). In no case may the allowable PSD increment exceed an NAAQS. Finally, visibility and other air quality-related values must be incorporated into any decision to grant a permit.

TABLE 3. PSD MAXIMUM ALLOWABLE INCREMENTS

Pollutant	Maximum allowable increase ($\mu g/m^3$)
Class I	
Particulate matter (TSP):	
Annual geometric mean	5
24-hr maximum	10
Sulfur dioxide (SO_2):	
Annual arithmetic mean	2
24-hr maximum	5
3-hr maximum	25
Class II	
Particulate matter (TSP):	
Annual geometric mean	19
24-hr maximum	37
Sulfur dioxide (SO_2):	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	512
Class III	
Particulate matter (TSP):	
Annual geometric mean	37
24-hr maximum	75
Sulfur dioxide (SO_2):	
Annual arithmetic mean	40
24-hr maximum	182
3-hr maximum	700

State Implementation Plan

Each state must submit to EPA for approval a State Implementation Plan (SIP) that outlines how the NAAQS will be achieved for any non-attainment area in the state. The primary NAAQS for total suspended particulates and sulfur dioxide must be met by 1983. In the process of achieving attainment, reasonable further progress in improving ambient air quality must be pursued, with greater improvement expected for the initial period after approval of the SIP. A number of options to accomplish this plan are available to the states.

First, the state set emission standards more stringent than NSPS; or define BACT to be more stringent than NSPS. Second, lowest achievable emission rates (LAER) are required for new sources in non-attainment areas. In concept, LAER is like BACT, except that it does not take into account the secondary impacts (such as energy and economic impacts). In practice, however, application of LAER has been very much the same as BACT. In part, the similarity between BACT and LAER is due to the initial technology forcing nature of BACT. In time, the difference in allowable emission rates between LAER and BACT should increase as familiarity with and application of the control technologies increase. Another reason for the similarity lies in the difficulty with truly ignoring secondary impacts (such as the economic and social) in the application of LAER. Nevertheless, the definition of LAER is continually updated to reflect the most stringent LAER applied to a particular source category anywhere in the country. Third, reasonably available control technology can be applied to existing facilities. RACT is defined by the states. Fourth, the state may stipulate either an offset policy or growth allowance. Under offset, a new source of modification must obtain, by some means, a better than one-to-one emission reduction from other sources in the area. Such measures may include putting controls on another company's facility, paving dirt roads, or buying another emitting industry and putting it out of business. With a growth allowance approach, all forms of control may be even more stringent so as to undershoot the NAAQS ceiling. By such a policy, in essence, an additional increment is made available, which allows growth in minor sources or other flexibility in permitting without reaching the NAAQS ceiling.

Substantial penalties, such as suspension of grants and aid, may be levied against states that do not adequately manage their plans. Other requirements in the SIPs include air quality monitoring and reporting of emission inventories.

Section 125--Economic Disruption

Any requirement of the CAA that could lead to economic disruption, for example, through emission standards that precluded use of locally or regionally available coal, could be suspended by action of the President or the President's designee. As with the NSPS for fossil fuel electric generating facilities, however, validated accounts of local or regional disruption would probably have to be provided before a standard would be promulgated.

Other Considerations

Aside from the complexity outlined above, some uncertainty exists at this time about possible revisions to the TSP and sulfur dioxide standards. There has been serious discussion about establishing an inhalable particulate (IP) standard, whose practical relationship to the present TSP standard is uncertain. Also, EPA is presently conducting a major reassessment of the sulfur dioxide standard.

RESOURCE CONSERVATION AND RECOVERY ACT

Growing concern about the disposal of hazardous waste led to passage of the Resource Conservation and Recovery Act (RCRA) in 1976. While technically an amendment to the previously enacted Solid Waste Disposal Act of 1965, RCRA instituted sweeping changes in the types of wastes covered, disposal methods, the documentation of waste amounts generated and their transport, the role of the federal government, and the liabilty for penalties. As with many pieces of recent environmental legislation, the federal government takes the lead role in issuing standards and guidelines, with permitting authority granted to the states when their disposal plans meet acceptable standards. The act has two main divisions governing the treatment and disposal of hazardous wastes (subtitle C) and solid wastes (subtitle D), differing in proscribed disposal criteria and possible penalties for non-compliance. These two subtitles are explained below. In addition, other provisions in the act established an Office of Solid Waste within EPA to administer and set guidelines for waste disposal, and to provide federal support for research and development of new methods to conserve resources and recover resources from wastes.

In enacting RCRA, Congress was concerned that "land is too valuable a national resource to be needlessly polluted by discarded materials . . . " (3). Stimulus for the act came from Congressional concerns that new materials and methods for packaging were adding not only large volumes of wastes, but wastes that were potentially harmful to the nation's health and drinking water supplies. Also, Congress recognized that other pieces of environmental legislation, such as the Clean Air Act, would generate wastes from control technologies. In addition, millions of tons of resources in wastes that could have been recovered were routinely being buried.

Thus, Congress set out to provide financial and technical support to state and local governments for waste disposal, to regulate the disposal of various classes of wastes, and to improve methods and techniques for waste disposal, material conservation, and resource recovery.

Subtitle C--Hazardous Waste

Subtitle C governs the management of hazardous waste. Hazardous waste is defined as those wastes which, if not properly managed, pose a serious threat to human health or the environment. Criteria for determining whether a waste is hazardous include toxicity, persistence, potential for accumulation in animal tissues, flammability, and corrosiveness, among others.

Once deemed hazardous, wastes are subject to complete record keeping, labeling, identification of chemical constituents, placement in appropriate storage containers, and a manifest system for following the movements of the waste. Disposal and transport of the wastes are governed by permits, which may be administered by the states if their procedures meet with EPA approval. Hazardous wastes may be disposed of off-site from the place of generation, but EPA scrutinizes the selection of disposal sites.

The stringency of hazardous waste regulations will, of course, add a substantial cost to waste disposal and handling, depending on the particular hazards involved. Failure to comply with regulations can result in heavy fines and possibly, in some cases, criminal penalties. Recognizing that imprecise methods for determining whether a waste is hazardous may result in either exposure of populations to hazards or undue financial burdens upon waste generators and transporters, EPA has undertaken a careful program of methods testing and public comment.

Subtitle D--Solid Waste

Solid waste is governed by Subtitle D of the act. Solid waste refers to all wastes that are not subject to water pollution control, are not domestic sewage, are not nuclear wastes as defined by the Atomic Energy Act of 1954, and are not hazardous wastes covered in Subtitle C of the act. Sludge, the waste from flue-gas desulfurization (scrubber) systems used in controlling air emissions from sulfur in fuel combustion, is specifically identified as a solid waste in the act.

Major provisions of Subtitle D include guidelines for the establishment of regional waste planning units and subsequent statewide waste plans, the closing or upgrading of existing open dumps to meet criteria for sanitary landfills, and the prohibition of new open dumps. Under RCRA, a sanitary landfill is defined as a site where there is "no reasonable probability of adverse effects on health or the environment from disposal of solid waste at such facility" (Sec. 4004 of RCRA).

EPA has developed guidelines to be followed by the states in promulgating standards for sanitary landfills (4). Briefly, these absolute minimum requirements to be met by all solid wastes are as follows: First, while the location of disposal sites in floodplains is not strictly forbidden, such disposal sites are limited in instances where alterations to flood flow or water storage capacities of the floodplain might occur, or where there would be a risk from washout of the solid waste. Floodplains are defined by the 100-year flood criterion of the U.S. Army Corps of Engineers. Second, no site may be constructed that results in damage to an endangered or threatened species. Third, no site can discharge pollutants into surface waters in excess of national standards. Fourth, no site may contaminate groundwater aquifers in excess of standards. Fifth, wastes containing cadmium or polychlorinated biphenyls (PCBs) may not be applied as soil amendments for agricultural crops under certain circumstances. Sixth, wastes must be periodically covered or buried if the disposal site is a possible refuge for disease vectors, including flies, rodents, and mosquitoes. Seventh, open burning is forbidden, except for certain biomass wastes. Eighth, risks to safety are delineated.

For wastes not deemed hazardous, meeting the above criteria qualifies a disposal site as a sanitary landfill; a disposal site not covered under Subtitle C and not meeting the sanitary landfill requirements is classified as an open dump.

Wastes from Coal Technologies

As previously mentioned, sludge from flue-gas desulfurization (scrubber) units is singled out in the act as a solid waste. Many of the wastes that result from the coal technologies investigated in this report (see Chapter 6) are similar to sludge (see Chapter 9). Thus, it is instructive to follow the treatment of scrubber sludge under the rules proposed by EPA or promulgated under RCRA.

In its initial proposal for hazardous wastes under the act in 1978, EPA listed scrubber sludge as a hazardous solid waste (5). However, in the same proposal, EPA established an interim special waste category for large volume wastes that may be hazardous, such as scrubber sludge and flyash. Probably most of the other wastes described in Chapter 9 would also be in this category. Hence, the status of many coal-related wastes was very uncertain, and EPA embarked on an ambitious campaign to gain more information.

In its most recent determinations, resulting from public comments and further investigation, EPA eliminated the special waste category (6). The elimination resulted largely from two changes: (1) greater flexibility and phasing in the setting of standards; and (2) increasing the concentration ten-fold (from 10 to 100 times the concentration allowed by the Primary Drinking Water Standards) for waste extracts to be classified as toxic, and thus hazardous.

What effect such changes will have on coal-related wastes cannot be determined without additional research. Certainly, the difficulty of appropriately disposing of the large volumes of wastes previously placed in the special wastes category promises that their future regulation and disposal will be uncertain and volatile.

POWERPLANT AND INDUSTRIAL FUEL USE ACT

The basic intent of the FUA is to conserve natural gas resources and to reduce petroleum imports by mandating an expanded use of coal and alternative fuels in the electric utility and industrial sectors (7). However, environmental regulations are not to be waived nor is growth to be overly constrained. This act has frequently been referred to as the "coal conversion" act; its effectiveness will not be apparent for a number of years. The act also supports use of synthetic gas in lieu of natural gas. Language in certain portions of the act emphasizes curtailing the use of natural gas over petroleum; but agriculture is specifically identified as a priority sector for using natural gas.

The FUA is considerably less complex than either the Clean Air Act or the Natural Gas Policy Act. The FUA may be characterized according to intent, applicability, prohibitions, exemptions, and enforcement. Only those provisions of the act relevant to industrial boilers will be addressed here.

The FUA is a refinement and augmentation of the Energy Supply and Environmental Coordination Act of 1974. With respect to conversions of industrial boilers to coal, however, the ESECA was ineffective. The FUA is not necessarily destined to follow the same pattern, because its regulatory approach, which is described below, differs from that of ESECA.

Applicability

Both new and existing installations over a given size and not covered by exemptions are subject to the act. In the case of new facilities, the provisions of the act apply to facilities with a 100 x 10^6 Btu/hr, or greater, heat input design capability; for existing facilities the cut-off is 300 x 10^6 Btu/hr. The coal technology facility sizes presented in Chapter 6 are covered under the FUA.

A significant loophole exists, which may permit the circumvention of the FUA. Facility size is based on a "unit," which, in the language of the act, refers to a single boiler with its ancillary equipment. However, an industrial firm's needs for process steam could be met by a number of single units, each smaller than the specified cut-offs, but exceeding them in total. (Aggregations of new units with a total capacity over 250 × 10^6 Btu/hr are covered under the act.)

The major difference between ESECA and the FUA is that under the FUA, the burden of proof for not converting to coal is the responsibility of the firm. Under ESECA, the determinations of applicability were made on an individual, case-by-case basis by the federal government when a firm announced its intentions to install natural-gas- or oil-fired boilers.

Prohibitions

Unless specifically exempted, new industrial boilers are prohibited from using natural gas or petroleum. Other categories of industrial process-energy needs (such as direct heat) to be met with new capacity are subject to rule making by the Secretary of the Department of Energy. Technical feasibility, geographic location, and size are considered in applying prohibitions to these other process-energy categories.

Prohibitions on using natural gas and petroleum in existing facilities are substantially less severe. If existing facilities are not otherwise exempted, only those that have or previously had the technical capability of using coal or alternative fuels, or those that would not require substantial physical modification or result in substantial derating, may be prohibited from using natural gas and petroleum. (In certain cases, such facilities may be required to burn coal-oil mixtures.) The relative insignificance of this "prohibition" population of existing installations is demonstrated by the fact that only 28 installations have received orders prohibiting oil or natural gas use since passage of the FUA (see Chapter 4 for more discussion).

Exemptions

The key to realizing the intent of the FUA lies in the exemptions provided for in the act. For example, the act is very clear concerning the inviolability of applicable environmental requirements. Both the Clean Air Act and the Resource Conservation and Recovery Act (cited as the Solid Waste Disposal Act) are specifically mentioned as "applicable environmental requirements," along with others. Therefore, use of petroleum or natural gas may not be prohibited if substituting coal or alternative fuels would violate standards.

Because of the key role of exemptions and their importance to the analysis in this report, it is necessary to outline them fully. Depending on the particular constraint, temporary or permanent exemptions may be approved for new or existing facilities.

Site Limitations--

Physical limitations resulting from inaccessibility of coal or alternative fuels, lack of transportation facilities, lack of space for the handling and storage of fuel, lack of space for pollution control equipment or for waste disposal, or lack of adequate water may qualify a facility for exemption. Presumably, factors such as the costs of retrofitting pollution control equipment or off-site waste disposal may also apply to the cost calculus mentioned below. Chapter 4 discusses some of these physical limitations in greater detail.

Environmental Regulations--

Exemptions may be granted if environmental regulations would be violated by conversion. Besides the specific acts noted above, all state and federal regulations pertaining to water or air pollution, solid waste disposal, or pollution from control technologies associated with conversion, apply. These topics are fully addressed in Chapters 7, 8, and 9.

Cost Differences--

If "substantially" higher delivered energy costs resulting from transportation distances, fuel costs, or pollution control would arise from coal conversion compared with using imported petroleum over the lifetime of a facility, an exemption may be granted. The qualifier, "substantially," is crucial to any determinations. The Department of Energy has gone through several iterations, attempting to define what would be a "substantial" cost differential. Cost sensitivities are addressed in Chapter 10.

Public Interest--

A temporary exemption may be granted if it is in the public interest; however, "public interest" is not well defined in the act. The Secretary of the Department of Energy determines whether or not an exemption is in the public interest. Perhaps the best explanation of such an exemption is an example. In 1979, there was an unexpected surplus, or bubble, of natural gas. In order to reduce oil imports at that time, the DOE requested that all facilities capable of burning natural gas do so, and temporarily switch away

from oil. The so-called bubble still exists to a degree and DOE, at least for the near-term, is still advocating that oil-fired units with the capability to burn natural gas do so.

Other Exemptions--

Certain exemptions for coal-oil mixtures, use of synthetic fuels, the employment of innovative technology, the use of cogeneration, or the violation of certain state and local requirements may also be granted.

Enforcement

The FUA itself stipulates only criminal and civil penalties for violations of the provisions of the act. While financial assistance to some regions and to railroads is also authorized in the FUA, it is unlikely that any assistance would be given to industries to counteract possible impacts. (But electric utilities may receive assistance for installing pollution control equipment that might be required when converting to coal.) Other portions of the National Energy Act, of which the FUA is a part, provide for tax incentives, penalties, and deregulated natural gas prices to accelerate coal and alternate fuel use.

NATURAL GAS POLICY ACT

Natural gas prices have been regulated in U.S. interstate markets since the passage of the Natural Gas Act in 1938. Prior to the passage of the NGPA, the disparity between the relatively low cost of natural gas in the interstate market and its cost in the intrastate market, which was higher, meant that most natural gas was sold in the intrastate markets. As a result, natural gas was not available in certain regional markets, which led to an increasing reliance on imported oil in those markets served by the interstate distribution system.

The Natural Gas Policy Act of 1978 was designed to redress such inequities and to provide for gradual gas price increases to the market, or deregulated, level (8). In addition, priorities for gas allocation are established in the act. The act is very complex because of the regional nature of the existing gas problem, the need to balance the pricing inequities against the possible windfall profits to natural gas suppliers that could result from deregulation, the establishment of priority users for gas, and the numerous types of gas. All told, there are eight general categories of gas addressed in the act, with over thirty possible classifications (9). These range from old to new gas, from deep wells to marker wells, and from offshore to inland gas. A pricing scheme is outlined for each classification, with various allowed price increases and timetables.

The major provisions of the NGPA cover price controls, deregulation of certain gas, incremental pricing for gas, emergency authorities in the case of a gas shortage, and curtailment priorities. The latter provision coupled with the way gas is priced to various users could affect the attractiveness of natural gas to industry.

Price Controls

A series of statutory maximum prices are set for the various categories of gas. Disparities between intrastate and interstate gas are to be eliminated. Prices for the gas are adjusted monthly for inflation, with some gas prices also allowed to rise at an additional rate of 3.5 to 4.0 percent per year. Such increases are designed to lead to decontrol by the mid-1980s. However, if the annual price increases are insufficient to bring gas prices to market parity, the problem of windfall profits would again arise. Gas sold above the allowable price set by the Federal Energy Regulatory Commission (FERC), which administers the act, could result in criminal or civil penalties to the producer.

Deregulation

Certain intrastate gas, new gas, and other high cost gas are set to be deregulated by 1987 (some by 1985). Gas not set for deregulation follows the scheme of price controls outlined above. If need be, the President or Congress can reestablish price controls for the deregulated gas for one eighteen-month period between 1985 and 1987.

Incremental Pricing

This section addresses how distributors may pass on the rising costs of natural gas. In essence, higher costs are to be borne by large industrial users raising steam. In time, other industrial users (producing direct heat, for example) and smaller industrial users may also be subject to the higher prices. Schools, hospitals, and electric utilities are exempt from the incremental price increases, and some small industrial and agricultural users may also be made exempt, subject to rule making by the FERC and approved by Congress.

Only when the higher prices to the gas distributor cannot be absorbed by the groups targeted for incremental pricing, will other gas users, such as in the residential and commercial sectors, be subject to higher prices over an inflation-adjusted baseline. The level of the upper ceiling for the increment to be charged to the targeted groups is defined by the price for residual or distillate fuel oil, depending on the region. In other words, targeted groups, such as large industrial steam-raisers, will continue to bear the entire incremental price increase as long as the price of gas does not exceed the price of fuel oil.

Two factors will combine to keep gas prices to residential consumers comparatively low. First, according to the act, a whole hierarchy of users would be subject to incremental pricing before residential and commercial users become liable. Second, because petroleum prices have risen faster than anticipated when the act was being deliberated, the incremental share targeted to industrial users is much larger than originally projected. Presumably, these factors will lead to further natural gas conservation by industry. However, as discussed in Chapter 10, a least cost approach to evaluating the future fuel decisions by industry is subject to qualification. And, as discussed in Chapters 7, 8, and 9, the coal alternative may not be acceptable for many industries. Thus, the real competition may be between petroleum and natural gas, and not coal and natural gas.

Finally, it should be mentioned that the residential and commercial consumers are not protected from increased gas prices in all cases. Alaskan gas from Prudhoe Bay is excepted in most cases, as well as some liquefied natural gas (LNG) imports. The FERC may also exempt other types of gas, subject to Congressional review.

Emergency Provisions

Under a natural gas shortage declared by the President, gas may be specifically allocated to "high priority" users for a 120-day period. High priority users include residential and commercial users, and users whose life, health, or property maintenance would be endangered in case of a gas shortage.

Curtailment policies for a hierarchy of users are also established under the emergency provisions of the act. Essentially, these policies provide a plan for restricting gas supplies during a shortage. At the top of the heirarchy are high priority users, followed by certain agricultural and industrial users.

Effectiveness of the Act

Since enactment of the NGPA, three factors have substantially changed the climate surrounding natural gas use. First, oil prices have risen faster than expected. Second, natural gas supplies are being found at a faster rate than anticipated. And third, conservation of natural gas use has proceeded more quickly than projected. Unfortunately, the way these factors combine to alter the effectiveness of the NGPA is not clear. But, one conclusion, at least, may be drawn: political realities and the vagaries of a changing world severely limit the ability of government to control energy use by means of pricing mechanisms.

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CHAPTER 4

TECHNICAL AND LOGISTICAL FACTORS AFFECTING INDUSTRIAL USE OF COAL

The preceding chapter has addressed some of the key regulatory actions relating to fuel use in industrial boilers. Although these will be of major importance to firms considering a switch to coal, there are a host of technical and logistical factors that will need to be considered before decisions on fuel/technology systems can be made.

It has been estimated that, unless existing boilers received major technical modification, fully 90 percent of them would be incapable of burning coal (1). It is conceivable that, owing to uncertainties over air quality and other environmental regulations and the apparent conflict between these regulations and energy policies, industries will have a tangible incentive to continue operating and, possibly, expanding existing facilities rather than constructing new plants (2). At the same time, the amount of boiler capacity expected to be deployed in new "grassroots" industrial plants over the next twenty years will be quite small (about 20 percent) compared with existing capacity (see Figure 16). Thus, the proportion of year 2000 total industrial boiler capacity that will be installed in plants constructed after 1980 might well be insignificant, relative to existing capacity. For these reasons, any substantial near-term increase in the use of coal for generating industrial steam may have to be accomplished through conversion or replacement of existing boilers fired by natural gas or oil.

Conversion or replacement programs, however, may be impeded by a host of technical, regulatory, and logistical constraints. Some indication of the severity of these constraints can be gained from a brief review of the effects the Fuel Use Act and antecedent legislation have had upon industrial energy use. As noted in Chapter 3, a variety of circumstances can exempt an industry from the provisions of the Fuel Use Act. Of the original survey conducted by the Federal Energy Administration of 6200 industrial boilers, 780 were identified as being coal-capable; that is, they were originally designed to use coal but had subsequently been modified to burn oil or gas. Those boilers could be technically modified to revert to coal. Of these 780 boilers, 752 were exempted, on the basis of one or more circumstances, from the act's provisions (3). A later survey of approximately 300 additional boilers identified 200 as being located in cities where ambient air quality standards were violated (see Chapter 7). Of the remaining 100 units, all were already using coal on at least a part-time basis.

A number of tentative conclusions can be drawn from these facts. Apparently, the majority of coal-capable boilers currently burning gas or oil cannot be reconverted to coal. Although air quality regulations are evidently the dominant constraint, these regulations are subject to review and possible alteration. In nearly every instance, however, the technical and logistical factors reviewed in the following section, which also pose potentially serious impediments to increased coal use, do not arise from government policy, and hence, cannot easily be mitigated through public policy action. Additionally, the evidence suggests that the great majority of boilers technically capable of burning coal, and not subject to any exemptions under the Fuel Use Act, have probably already changed to coal. Therefore, the following discussion focuses on existing industrial plants that have not used coal in the past.

Finally, one important caveat should be applied. The following discussion adopts a "worst case" perspective as a method for identifying all of the possible constraints. Many of the factors addressed below are site-specific. The actual situation at any given industrial plant will be strongly influenced by regional location, size and type of industry, and many other specific circumstances. In order to gain a greater sensitivity to these variables and to help correlate constraints with respect to industry characteristics and regional differences, we undertook an extensive interview campaign with plant managers and corporate officials. The results of these interviews are presented in Appendix A and provide the context within which industry- and region-specific fuel choice decisions are analyzed (Chapter 10).

REVIEW OF CONSTRAINTS

Technical Obstacles

A fundamental restriction to rapid substitution of coal for oil and gas in industry is the fact that coal cannot be burned in boilers originally designed to fire liquid or gaseous fuels. Boiler design is primarily a function of fuel characteristics. Shifting from liquid or gas to a solid fuel is particularly difficult since it entails entirely new fuel storage, handling, and injection systems in addition to modified combustion and heat transfer equipment. Indeed, there exists a general consensus among industrial users that it is practically impossible to convert gas or oil boilers to coal (4).

The high ash content and other chemical and physical properties of coal have a significant impact upon boiler design and operation. At high temperatures, the ash in coal melts and forms slag. Slag deposits lower the heat transfer rates across boiler walls and convective tubes. Also, slag and ash deposition in the economizer section may result in increased pressure drops through the boiler. To prevent slagging, heat release rates must be lowered 50 pecent in coal-fired boilers (5). The convective section is also vulnerable to erosion from the hard and abrasive oxides of iron and silicon common to flyash (6). To minimize erosive effects, gas velocity must be 50 to 70 percent lower in coal boilers, and convective tubes must be spaced eight to sixteen times farther apart than in gas or oil units (5). These design differences combine to result in a steam derating of at least 50 percent, and possibly as much as 70 percent (7). Put simply, the coal-fired boiler must have at least twice the radiant surface area of a gas or oil boiler of equal capacity; or conversely, a coal-fired boiler of equal size to a gas or oil unit will have less than half as much energy productivity.

To discuss "modification" of gas and oil units to burn coal is misleading. Actually, the boilers must be almost completely rebuilt, often with different construction materials, in order to accommodate coal. These alterations are so extensive that, for a given capacity, the costs of modification have been estimated at 97 percent of the cost of a new coal-fired unit (5).

It is quite obvious that a switch to coal involves replacing existing gas or oil units with new boilers capable of burning coal. Replacement, however, entails numerous changes in overall steam plant design, operation, and maintenance.

Besides the boiler itself, a number of auxiliary equipment units are required for a changeover to coal. Facilities and equipment for unloading, storing, preparing, and transporting the coal to the boiler must be installed. A system for removing ash from beneath the boiler must also be included, and this often requires major structural modifications of the boiler house itself. Similarly, modification of ductwork and replacement of draft fans will probably be required in installations changing over from oil or natural gas to coal (5).

Costs

The primary impact of modifications required for coal utilization will be greatly increased costs (detailed cost analysis is presented in Chapter 10). Since conventional coal boilers are nearly twice as large as equivalent capacity gas or oil boilers, most units will have to be constructed at the site. In contrast, most natural gas or oil boilers can be shipped to the manufacturing plant as a "package." Coal-capable units of 50 x 10^6 Btu/hr (50,000 lb/hr steam) or greater capacity generally need to be field-erected. This significantly raises boiler capital costs. Total capital costs are further escalated by the extensive ancillary equipment needed to accommodate coal utilization. Figure 4 compares the capital costs of a gas or oil boiler and a conventional stoker-fed water-tube coal boiler equipped with a scrubber. As shown by the figure, capital costs for coal-fired units are two to five times greater than those for gas or oil.

Operating and maintenance costs are much higher for coal burning equipment than for boilers fueled by gas or oil. Coal burning requires additional personnel to perform and supervise boiler and coal handling operations. The added labor intensity is the primary contributor to increased operation costs. Problems of slagging, ash deposition, erosion, and corrosion raise the maintenance cost. Coal-fired boilers must be periodically shut down for cleaning operations, and corroded or worn parts must be replaced. Figure 5 shows operating and maintenance costs for coal boilers compared with costs for those

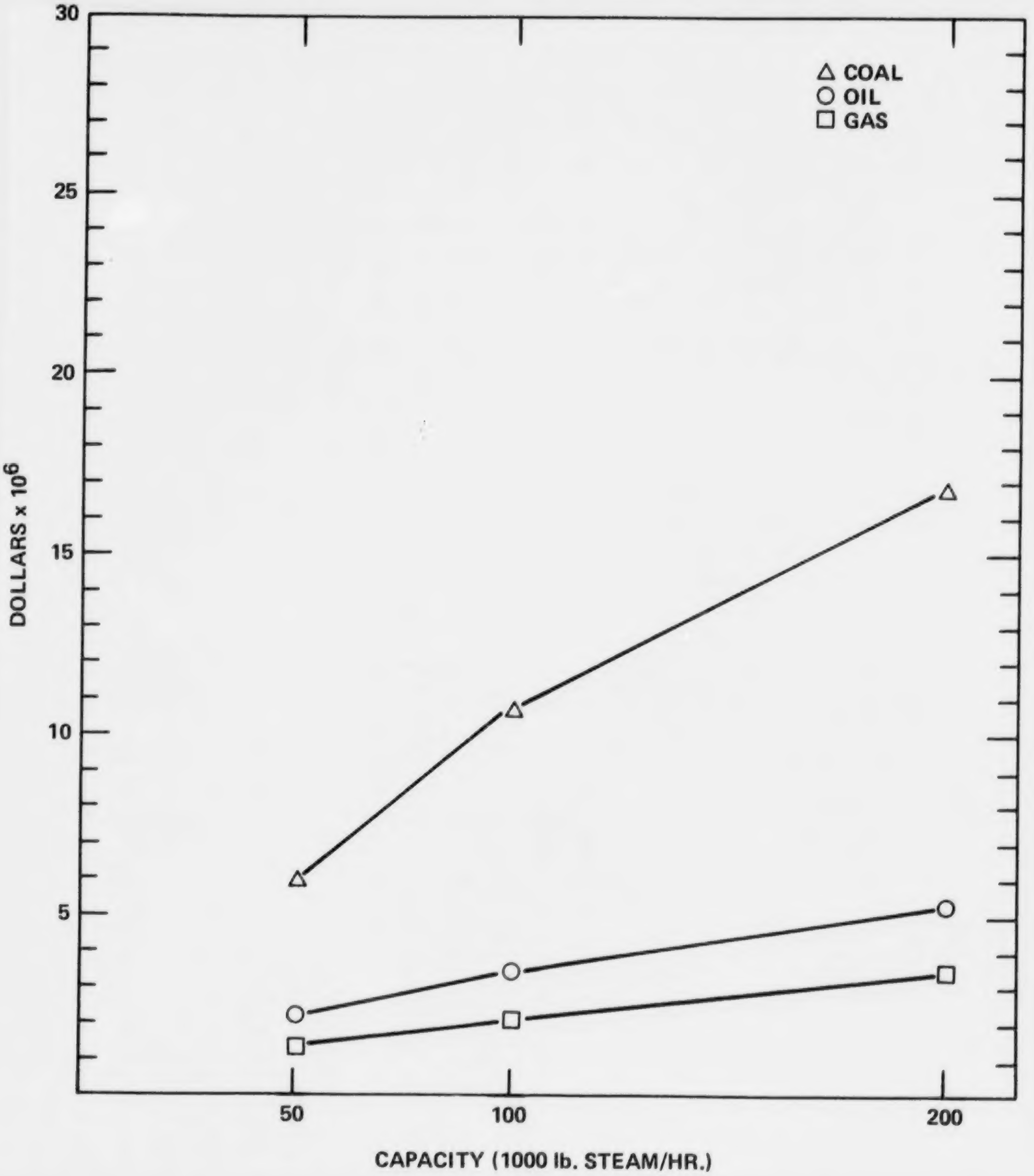

Figure 4. Comparison of capital costs for coal-fired and gas- and oil-fired boilers (1980 dollars).

burning oil or gas. Estimates from various studies conclude that operating and maintenance costs range from five to ten times greater for controlled boilers fueled by coal (see Chapter 10).

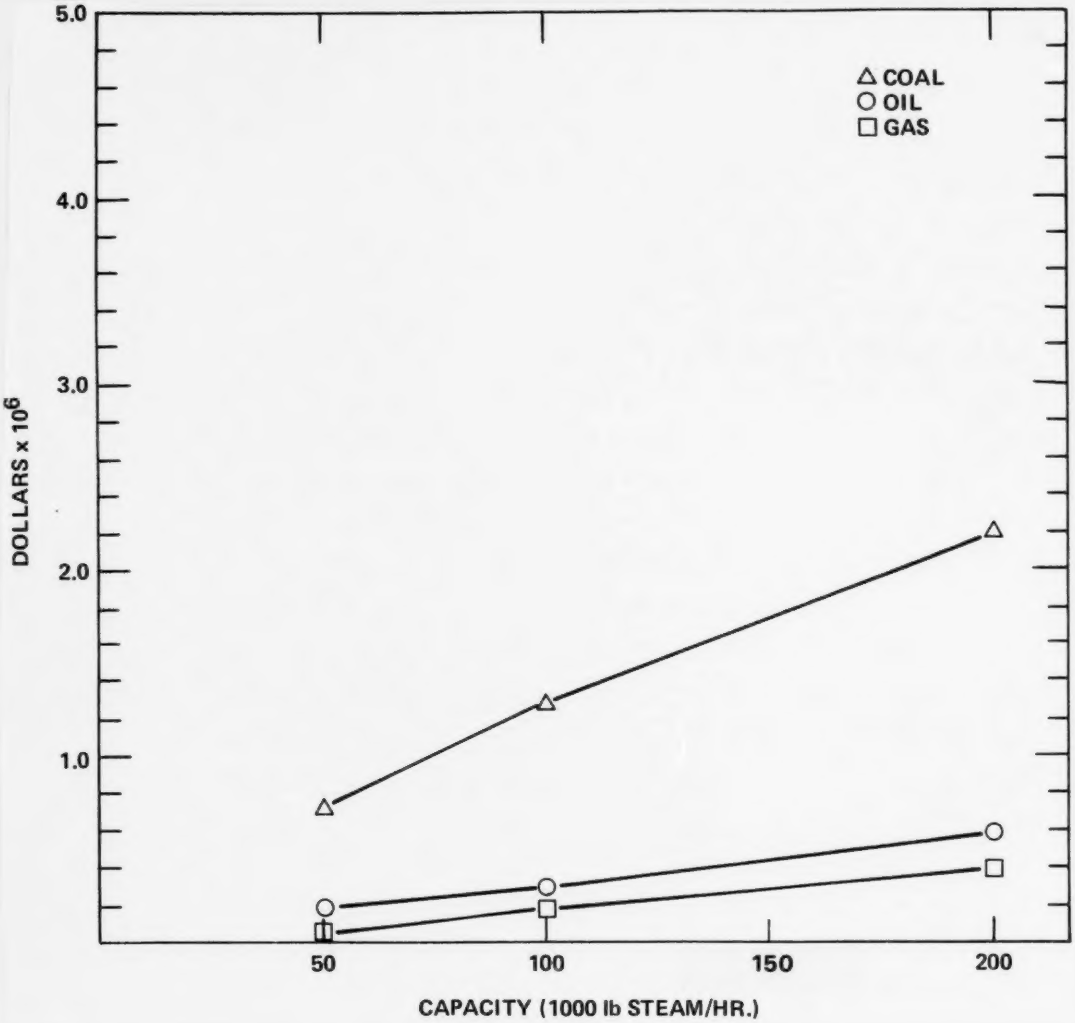

Figure 5. Comparison of operating and maintenance costs for gas-, oil-, and coal-fired boilers (1980 dollars, load factor: 100%).

Both the high capital investment and considerable operating and maintenance costs contribute to the pronounced economies of scale associated with coal utilization. For example, a coal handling system capable of processing 1000 tons a day would cost approximately two or three times more than a system designed to process 50 tons per day, rather than the twenty times that might be expected (8). This feature of coal technologies is evident in Figures 4 and 5. Unit costs for smaller users can be expected to be exceptionally high. Generally speaking, direct use of coal in industrial boilers is economically feasible only in boilers producing 100,000 lb/hr of steam or more (9). A second result of scale economies in coal use is that incremental increases in a plant's energy consumption are too expensive to accomplish by coal utilization (10). Thus, plants that burn oil or natural gas and that need to increase steam plant capacity only modestly will be strongly inhibited from meeting their incremental demand with coal.

The economic penalties of coal utilization must be offset by lower fuel costs in order for coal to become competitive with natural gas and oil. Advantageous fuel costs will result in net savings to the consumer only if the annualized fuel costs are differentially low enough to offset the relatively higher fixed costs of operating a coal-fired energy system. The need for this offset, in combination with factors of scale, suggests that coal firing will be attractive only to larger energy consumers in the manufacturing sector.

Even for the larger energy consumers, though, the general pattern is to operate many small boilers at a fraction of their potential capacity. Questions have thus been raised as to whether most manufacturers operate on too small a scale ever to attain attractive economies with coal use (11).

Logistical Factors

Even for those firms that would find it economically and technically feasible to replace existing gas or oil equipment with coal-capable technologies, the shift to coal may be hindered by physical and logistical constraints. Of particular concern in the manufacturing sector are space availability and issues of transportation and supply. The logistical considerations reviewed below are extremely sensitive to regional differences. For example, in regions that have historically produced and consumed large amounts of coal (Appalachia, for instance), the supply infrastructure has remained relatively intact. Similarly, in plants that have burned coal in the past, space allocation may not be especially problematic. Still, logistical difficulties in obtaining reliable supplies of coal, and the possibility of having to alter an existing plant configuration in order to accommodate a coal-fired steam system, are of general concern to industrial firms.

Space Requirements--

The generally urban location of U.S. industry limits the availability of land and places a premium on space. Proximity to markets, labor, water, utilities, raw material supply and product distribution infrastructures, and transportation networks have remained influential in keeping industries in or near municipal areas (12, 13). Additionally, the internal arrangements of manufacturing complexes--whether the firm is in a municipal area or not--are designed to maximize materials transport and efficiency of production processes; prudent use of available space is compulsory. What excess space is available has generally been set aside for eventual expansions in a plant's productive capacity.

Use of natural gas or oil imposes only minimal requirements for facilities to store, transport, and utilize the fuel. Coal use, however, demands much more extensive accommodations. Specifically, substantial space is needed for housing the boiler, storing and handling the coal, housing pollution control installations, and disposing of solid waste. In some older industrialized areas, the land needed to fulfill the incremental space demand created by coal conversion simply might not exist (3, 14). It should be noted that features of space allocation and availability are essentially site-specific. In some instances, more than adequate space may exist, and such adaptations as overhead storage bins or remote stockpiling arrangements may provide some flexibility in space utilization. Yet, because of the space required for coal use, and the essentially urban, often compressed design of most manufacturing establishments, lack of adequate space is commonly cited as a major obstacle to industrial conversion to coal-based energy technologies.

As mentioned in the discussion of costs, coal-fired boilers are about twice as large as an equivalent capacity oil or gas boiler. Structural modifications needed to accommodate the larger boiler could conceivably be hindered by a lack of room for expanding the existing facility (15). A new module for housing the boiler may have to be constructed, provided that the necessary space is available, and the new construction will further escalate costs.

The space problems of boiler location when replacing gas or oil units with coal will be magnified to a significant degree if emission control is mandated. Advanced technologies for particulate and SO_2 control are generally bulky, space-consuming structures. Furthermore, they must be located nearly adjacent to the boiler. The space required to install control technologies thus may be expected to pose a serious obstacle to boiler replacement (16). Installation of pollution control devices may require relocating the boiler house--and thus redesigning or modifying much of the entire steam plant layout--if adjacent space is unavailable. Location or relocation of the boiler, in turn, affects the entire energy system design.

Should boiler replacement require that a coal-capable steam plant be located on the periphery of the manufacturing complex, substantial energy losses may be experienced. For example, in a survey of 250 industrial plants, R. C. LeMay Associates concluded that boiler location is often too far removed from principal load centers (17). The survey revealed a number of instances in which the actual cost of steam at the point of use was double the cost at the point of generation. In recent years, installation of packaged boilers in close proximity to individual processes has become an increasingly important, and widely adopted, energy conservation strategy (8). Not only does such a strategy decrease heat losses from extensive steam pipe networks, but also enables processes to be operated more efficiently (18). Thus, boiler replacement projects should be evaluated on the basis of potential impacts on productivity as well as costs.

Facilities for coal storage and handling occupy a large fraction of the land needed to convert to coal. Unlike gas, which does not need to be stored or handled at all, and oil, which can be stored underground or in tanks and piped to the site, coal requires on-site storage. A ninety day supply of coal for a moderate size industrial steam plant (400,000 to 500,000 lb steam/hr) would occupy one to two acres of land. About three times as much land would be required to support the entire coal handling system--unloading, storage, and preparation (19). In many instances, this land may not be available.

The logistics of coal storage could be further complicated by local zoning ordinances that prohibit visible storage of raw materials (19). Coal piles may have to be contained within sheds or landscaped in a manner that obscures them from sight. Each of these solutions would increase space requirements as well as costs.

Coal combustion produces solid residues that must be retrieved, transported, and disposed of (see Chapter 9). Additionally, emission control devices greatly increase solid waste production. This is especially true for flue-gas scrubbing units, which produce a wet sludge that is difficult to handle and occupies a much higher volume per unit weight than does ash or other dry wastes. Since solid wastes must be disposed of in ponds or in landfills, extensive land areas must be available.

Costs of solid waste disposal are most sensitive to transportation requirements. Transporting the wastes for off-site disposal will impose quite severe economic penalties. Even if an on-site area is obtainable, it may be impossible to dispose of large quantities of solid wastes there without violating state or municipal land use codes (4). Land must be legally as well as physically available. Indeed, disposal of the ash presently produced from coal use or residual oil firing is a major problem in many existing industrial plants (5, 8). Most public landfills will not accept flyash, and others are being closed or are nearing limits for receiving additional wastes of any kind (20). Widespread conversion from gas or oil to coal can only aggravate these problems, especially if emissions must be controlled to meet state or federal air pollution regulations.

The fact that many manufacturing establishments have municipal locations compounds disposal problems, since appropriate sites for landfilling urban refuse and other industrial wastes are becoming increasingly scarce (21). Acreage needed for the additional solid waste burden created by conversion to coal may not only be unavailable at the plant site, but moreover, disposal areas in the near vicinity may also be unavailable for disposal of coal combustion wastes. Implementation of the Resource Conservation and Recovery Act will also have direct effects on disposal of solid wastes from coal use, as discussed in Chapter 3. RCRA stipulations generally will inflate the acreage needed for disposal and restrict the number of sites suitable for disposal.

Replacement of an existing gas or oil boiler with one capable of burning coal is much more complicated than just switching boilers. Various ancillary equipment and facilities not required for gas or oil use must be included. Beyond the costs involved, the land and space required to install these facilities may be a strong impediment to coal substitution. Furthermore, even if the requisite space is obtainable, it may not be optimally located with respect to achieving an integrated steam plant design and to providing the most efficient service to process load centers.

Transportation Requirements--

Another logistical aspect that must be accounted for by firms considering a shift to coal is transportation of the fuel from the mine to the plant. Unlike gas and oil, which transport conveniently in underground pipelines, coal is cumbersome and costly to haul. All systems currently available for transporting coal are subject to interruption. Temporary lapses in service may be caused by inclement weather, labor unrest, fuel shortages, or intermittent unavailability of equipment. None of these factors can, of course, be controlled by the consumer.

Transfer of solid coal from point of extraction to point of consumption can be accomplished by train, barge, truck, or slurry pipeline. Slurry pipelines have severe economies of scale and are only economical for high volume and long distance coal transport. Furthermore, while they are feasible for the largest utility plants, they are unattractive, impractical, and inappropriate for individual industrial users. Barge transportation is most economical, but is available to only a limited number of consumers. Shipment of coal by truck is a viable alternative for short distance hauls to small users, though federal and state weight limitations discourage most truck transportation of coal (3). Railroads have historically been, currently are, and most likely will continue to be the dominant mode of coal transportation. In 1976, 75 percent of the coal conveyed from mine sites was shipped by rail.

Manufacturers considering a shift to coal will in most instances need to have access to railway connections. Access should not present any problem to most industrial plants, since connections usually already exist (12). The additional traffic fostered by a shift to coal, however, may necessitate installation of new rail spurs to accommodate frequent coal shipments. Alternatively, the existing connection may need to be elongated or rerouted in order to reach the coal storage depot. Expansion or modification of existing railway facilities could potentially be impeded by space availability. New industrial plants planning to use coal may experience some difficulties in gaining access to rail networks since good sites are becoming scarce and recently have been at a premium (19). Manufacturing complexes accessible to barge shipping lanes might need to enlarge their dock facilities to accommodate coal shipments. Industries lacking access to either barge or rail lines will be forced to arrange for truck shipments and will probably pay substantially higher transportation costs as a result.

Not only is access more reliable for gas and oil than for coal, but also, the transportation costs are higher, more uncertain, and less predictable for coal. The extensive pipeline network for gas and oil that was built after World War II provides year-round reliable delivery, as well as inexpensive and predictable costs of service. Users pay only a proportional fraction of the annualized operating costs. For many pipelines, capital costs have largely been amortized and the fraction of delivered fuel price comprising transportation costs is modest; future costs are fairly predictable and certain. Modes of surface transportation are subject to various cost factors that result not only in variable and higher costs, but uncertainty over future costs as well. Common carrier regulation, market competition, costs of labor, materials, fuel, and inflationary pressures generally all influence the costs of coal transportation and contribute to its economic instability. Recent events have confirmed the vulnerability of truck transportation to rapidly escalating fuel prices and strikes. The railroads are still experiencing great economic difficulties. As common carriers, both are prevented from entering into long-term contracts that could guarantee the price of service over a number of years. Rail transportation costs have followed the historical precedent and still comprise a significant fraction of the total delivered fuel price. In some places, the cost of transporting coal to power plants exceeds the cost of the coal itself.

Rail delivery of coal to manufacturing plants may be hindered by a number of other logistical constraints as well. Recent expansion in utility coal demand has been supplied by unit train deliveries. Unit trains are economically advantageous in that they can attain significant economies of scale. It is unlikely, though, that individual industrial coal users will have enough demand to be able to benefit from unit train delivery. Shipments to manufacturing plants will be in single car loads. Costs for single car shipments are about double those of unit trains (22). Also, loading facilities at mines have been designed to accommodate unit train loads of coal. Some coal companies may have to redesign or build new loading equipment to allow single car shipments (23).

Finally, there is a great deal of concern over the ability of the railroads to meet escalating demands for coal. Some feel that rail transportation poses a "bottleneck" to increased coal use (4, 15). There is concern over whether the aging roadbeds could handle large increases in traffic. Sufficient supplies of rolling stock may also be unavailable (24). Manufacture of new equipment has been hampered by a lack of steel for wheels and rails (4). Though the U.S. railway situation is far from clear, it seems likely that, until potential users feel more certain about the ability of rail shipment to provide service to widely dispersed, relatively small, industrial users at a reasonable and relatively stable cost, transportation will prove a major obstacle to greater industrial coal use and may restrict the use of coal to locations in close proximity to coal supplies. In many respects, the situation today is analogous to that of the 1920s.

Supply Problems--

The analogy extends to features of supply beyond the transportation component. Infrastructural arrangements for marketing and distributing coal remain somewhat fragmented and disorganized. Weaknesses in supply infrastructure have historically constrained reliable delivery of coal to small and dispersed users. There is no doubt that plentiful supplies of coal are physically available in the United States. Whether these vast resources can be mined, transported, sorted, and efficiently distributed to individual industrial users at a competitive price, and on a reliable basis, is a question that remains to be answered.

Presently, coal can be purchased through long-term contracts or intermittently on the "spot" market. Long-term contracts are advantageous in that delivered fuel costs are minimal and remain constant over the life of the contract. Such contracts, however, are generally available only to the largest coal users--utility power plants. There are two main reasons for this. First, a utility plant will pay the downside risk of opening and operating the mine for the duration of the contract--the consumer is obligated to buy a set amount of coal for a certain number of years regardless of whether it is needed (3). Marketing risks to the producer are effectively mitigated. Second, economies of scale play a significant role in the production as well as the utilization of coal. A substantial fraction of the cost of production is incurred when new mines are opened or an existing operation is expanded. High volume production for extended periods minimizes the annualized production costs. Long-term contract prices reflect economies of scale in production. As volumes or periods of continuous production decrease, costs will necessarily increase. Utility power plants use enough coal to enable mining operations to reach attractive economies in production. Furthermore, long-term obligations to purchase a set amount of coal entail little risk to power plants, since the market prospect for electricity will be nearly certain for the life of the contract.

Owing largely to economies of scale, producers may be reluctant to guarantee price on a long-term basis to small users. As volume decreases, production factors subject to inflation will account for a higher percentage of the total operating costs to the producer. Since inflation is difficult to forecast, producers run a greater risk of losing money (or profit) in a long-term contract with smaller users. Contracts with users in the manufacturing sector are also more risky, since a firm using coal could conceivably face bankruptcy during the contract period. A producer may be adversely affected by delays or losses in compensation proceedings.

Even if long-term contracts were available to industrial users, it is not certain that the users would choose to enter into them. Although such contracts offer certainty of price, they also entail a long-term commitment to coal. Uncertainty about coal use generally, and the uncertainty over future availability of preferable fuels makes firms reluctant to commit to coal (25).

The risks of entering into a long-term contract must be balanced against the risks of purchasing coal intermittently on the spot market. Spot market prices are usually much higher than contract prices. The price of coal sold on the spot market is generally determined by the marginal cost of producing it. To the degree that the price to the consumer reflects the marginal costs to the producer, coal prices on the spot market can be anticipated to rise with inflation and depletion of those reserves most economical to mine. Furthermore, producers will generally demand a higher rate of return on spot coal because there is no guaranteed market for it. Thus, the risks of mining coal for the spot market are greater than for the contracted utility markets.

Spot market prices are very unstable. For example, in September of 1974, the average spot market price was \$30.64 per ton compared with an average contract price of \$12.89 per ton (9). Five years later, coal was being sold in some areas on the spot market at about \$19.00 per ton, a price well below the cost of producing it (26). This instability results from fluctuations in supply and demand. Coal enters the spot market from two sources: companies producing specifically for it, and surplus production from other mines. At present, the coal market is demand-limited, which has resulted in a large surplus being available for spot purchases. Should recent trends continue into the future, however, the availability of coal on the spot market might be severely constrained.

Traditionally, coal for spot marketing has been produced by the many small, independent coal mining operations that cannot produce the quantities required by utility power plants (26). Inflation, slack demand, capital availability, and competition from larger, mechanized strip mining operations have combined to drastically reduce the number of small operators. Additionally, the mounting complexities in planning, permitting, and meeting worker health and safety and land reclamation requirements have accelerated the trend toward fewer mines with larger capacities (1). The declining output from small mines can be expected to lower the amount of coal available for spot purchases. Concomitantly, large mines, operating under more efficient management, are selling coal in advance of actual production. An increasingly greater number of mines are "captive" or dedicated operations. There presently is a concerted effort by the mining industry to prevent or minimize the costly production surpluses that in the past resulted from faulty projections of demand. Tighter management of coal production will lessen the amount of surplus supply entering spot markets. Thus, manufacturers considering a shift to coal are faced with the present unavailability and risks of long-term contractual agreements, and the prospect of a rapidly declining spot market supply.

The impact that these factors could have on attempts to increase coal use in the industrial sector could be severe. One observer, noting the changing structure of the mining industry, has concluded that the problems manufacturers will face in obtaining stable and continuous supplies of coal are "no less than horrendous" (20). Although standard economic theory would predict that smaller mines would open to meet industrial demand, the negative economies of scale associated with these operations are becoming even more pronounced, and would indicate that the price of coal available to industrial users may be far higher than is usually predicted. Moreover, the long-term economic viability of smaller operators cannot be assured. Whatever supply and marketing structure evolves to serve industrial users could be quite fragile.

One potential response to these problems would be the development of coal brokerage firms (1). Theoretically, brokers would purchase the amounts of coal required to enable the attainment of economies of scale in mining operations and subsequently sell the coal to a large number of individual industrial plants. It remains uncertain, however, whether the technical and institutional arrangements necessary to support such a system could be developed while maintaining a competitive price for coal. At any rate, such a structure is currently not in place. It is for these reasons that industry commonly views the future supply and price of coal as being no more reliable than that of natural gas or oil.

Further complicating matters are factors of coal quality. Design of boilers and coal handling and preparation equipment is dependent upon the chemical and physical composition of the coal to be burned (7). Once the system is installed, coal of uniform quality must be supplied. Even seemingly slight variations in the chemical or physical properties of the fuel can cause operational difficulties. Firms must, therefore, not only arrange for a supply of coal, but also, for the type of coal. A particular type of coal might be unavailable at any given time on the spot market, thus creating additional incentives for industrial users to seek and enter into long-term agreements.

Recent trends in mine-site coal preparation practices might also discriminate against the potential industrial user. Just as loading facilities have been converted to accommodate unit train shipments, much of the coal is pulverized for use in utility boilers (23). Pulverized coal boilers are practical and economical only for the largest industrial users. The great majority of industrial boilers are stoker-fed water-tube units that require sized coal. In some parts of the U.S. the small quantities of sized coal that would be needed by manufacturing plants cannot be obtained (27).

Currently, there appear to be some deficiencies in the marketing and distributional mechanisms needed to encourage greater industrial coal use. Of course, should demand for coal by the manufacturing sector increase substantially, it can be assumed that the supply will be forthcoming. Still, the technical and institutional infrastructure required to facilitate widespread supply of coal to manufacturing establishments is, in many areas, not presently in place (25). Logistical problems of coal supply may thus result in longer lead times for firms wishing to convert to coal.

Once the necessary infrastructure is established, reliability of coal supply will remain a major concern. Indeed, reliability of supply is the primary prerequisite for coal to become competitive with gas or oil (23). In the recent past, supplies of coal have been interrupted by miner strikes, inclement weather, and breakdowns in the coal transportation network. The adverse consequences of lengthy supply interruptions could not be tolerated by most industrial plants. As a consequence of the concern over supply interruption, manufacturers considering a conversion to coal will probably want to carry a 120-day supply of coal instead of the usual 60-day stockpile (4). Such precautions will exacerbate any difficulties associated with space allocation and availability. Similarly, arrangements for transporting coal from the mine to the plant may need to incorporate a degree of redundancy. Uncertainty over the general integrity of the coal supply infrastructure and precautionary measures taken against the possibility of supply interruptions will tend to aggravate the logistical problems associated with coal use. Until potential users feel confident that coal can be purchased, transported, and used reliably, coal's lower cost per unit energy will provide little incentive for widespread conversion of industrial boilers away from oil and natural gas.

Inconvenience of Coal Use

In lieu of all the infrastructural discontinuities, the capital demands, and the risks associated with expanded use of coal by industry, perhaps the greatest obstacle that needs to be addressed is the manifest inconvenience of coal use. Changeover to coal use presents persistent management and operational difficulties. Although convenience factors appear to be essentially qualitative in nature, for business enterprises these factors may cause unforeseen impacts that prove to have quantitative economic value. As a result, and following historical precedent, the inconvenience experienced in a changeover to coal-based energy technologies is a major disincentive to boiler replacement (24).

Natural gas is, in many respects, an ideal fuel for industry (9). The temperature range of combustion is sufficient to accommodate any process or steam application. Products of combustion are clean, product quality is maintained, and residual emissions are minimal. Gas-fired boilers require only minimal supporting facilities. These boilers require little maintenance, rarely need to be shut down, and can be operated and regulated nearly automatically with little or no attention (4). Both natural gas and oil are ideal boiler fuels. They are easy and safe to transport, handle, and store, and they ignite easily and burn consistently (6). Gas or oil boilers can therefore respond quickly and efficiently to load fluctuations.

Coal, on the other hand, must be stored, conveyed, and prepared before entering the boiler. Combustion is rarely uniform, residual emissions are often extremely high, and the physical and chemical properties of coal adversely affect the combustion control required to efficiently meet frequent load fluctuations. Use of coal presents problems to users owing to space requirements, physical plant support, capital costs, environmental considerations, and because of the greater complexity in operating coal-fired boilers.

In terms of convenience, the primary impact of switching to coal is that additional management and technical expertise will need to be devoted to energy-related matters. Even prior to actual installation, management attention must be given to the possible consequences a switch to coal might have upon plant productivity and competitive position. Arrangements for adequate supply and transportation of the coal must be made and monitored. Once installed, the system will require almost continuous overseeing. If advanced pollution control equipment must be installed, the demand for additional technical expertise will be raised further. Devoting additional attention to managing a power generating facility distracts management attention from the firm's primary activities of producing and marketing products for consumption. Whether the distraction is severe enough to impair a firm's business performance is difficult to judge, but it is for these reasons that industry prefers using small, simple-to-operate and maintain, gas or oil boilers that require minimum attention and operating expertise (25).

The inconvenience of coal use adds a degree of unpredictability to the entire manufacturing operation. The greater complexity, handling difficulties, and labor intensity of coal-fired industrial energy systems make firms reluctant to convert to coal, even in the absence of other constraints (19). Handling and operating difficulties make the steam supply system more vulnerable to temporary failures, and hence, make the user firm more vulnerable to productivity losses. Distraction of management and technical expertise from areas of research, development, and marketing may also have an indirect impact upon business performance.

CONCLUSIONS

Although an expansion in the industrial use of coal entails a host of difficult technical, regulatory, and logistical constraints, the risks of losing profit productivity from substantial shortfalls in supplies of natural gas or oil remain as a strong stimulus for coal conversion. The risk of rapidly depleting reserves of liquid and gaseous fossil fuels is perhaps still greater than the risks associated with the supply and use of plentiful domestic coal resources.

Realistically, though, widespread conversion will take a long time. Replacing gas and oil with coal as the dominant industrial fuel will involve the development and deployment of new technological and institutional structures. Until a general infrastructure has time to evolve in a fashion commensurate with the demands of industrial coal use, the imperatives of process needs and process innovation, the factors of convenience, and the logistical obstacles may combine to severely constrain a widespread conversion to coal by manufacturing industries.

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CHAPTER 5

CHARACTERISTICS OF BOILER USE IN THE INDUSTRIAL SECTOR

The industrial sector is the largest consumer of energy among the major sectors of the U.S. economy (namely, commerce, residences, industry, and transportation). Boilers are widespread in industrial plants and are employed to supply steam. The use of steam varies widely among industries, but it is commonly used to heat materials, to provide a source of hydrogen and oxygen in industrial processes, to power compressors, to generate electricity, and to provide space heat. But the pattern of energy use and the use of boilers is not consistent throughout the industrial sector. There are significant differences in the amount of energy consumed, the role of boilers, and boiler technologies (including rated capacity, fuel type, and heat transfer configuration) among major industries and among regions. These differences have important implications for a variety of U.S. energy policy issues, such as coal conversion and air quality control.

In this chapter, recent trends in industrial energy use and the characteristics of the current boiler population are discussed in statistical detail. This is done to provide a quantitative background for the arguments of the chapters that follow.

ENERGY CONSUMPTION

Industry's role as the largest consumer of energy in the U.S. economy has remained unchanged for the last several decades. In 1960, this sector consumed 15.8 Q Btu of energy in end use terms. In 1973, this figure had grown to 23.0 Q Btu; but by 1978, the total had dropped somewhat to 22.0 Q.

The industrial sector includes those activities of the U.S. economy that are related to agriculture, mining, construction, and manufacturing. In general, coal has played a much larger relative role in these activities in the past than it does at present. The industrial sector includes categories A through D (major sector numbers 1-39) in the Standard Industrial Classification (SIC) system (1). Figure 6 shows the end use energy consumption of the industrial sector during the period 1960 through 1978 in comparison with the values for the commercial, residential, and transportation sectors. This statistical presentation illustrates the dominant consumption of the industrial sector--from 36 to 41 percent of the total annual U.S. energy end use consumption. Since 1963, the trend has been for some decline in the relative share of the industrial sector, little change for the residential and commercial sectors, and growth in the share for the transportation sector.

The fuels and energy carriers consumed by industry are used for a wide variety of purposes, including steam generation, process heaters, lights, space heating and cooling, electrolysis, electric motors, and so on. By way of presenting an aggregate picture, Figure 7 divides 1974 energy consumption in the industrial sector among generic end use functions. The highest end use shares are for process steam (41 percent) and direct heat applications (28 percent).

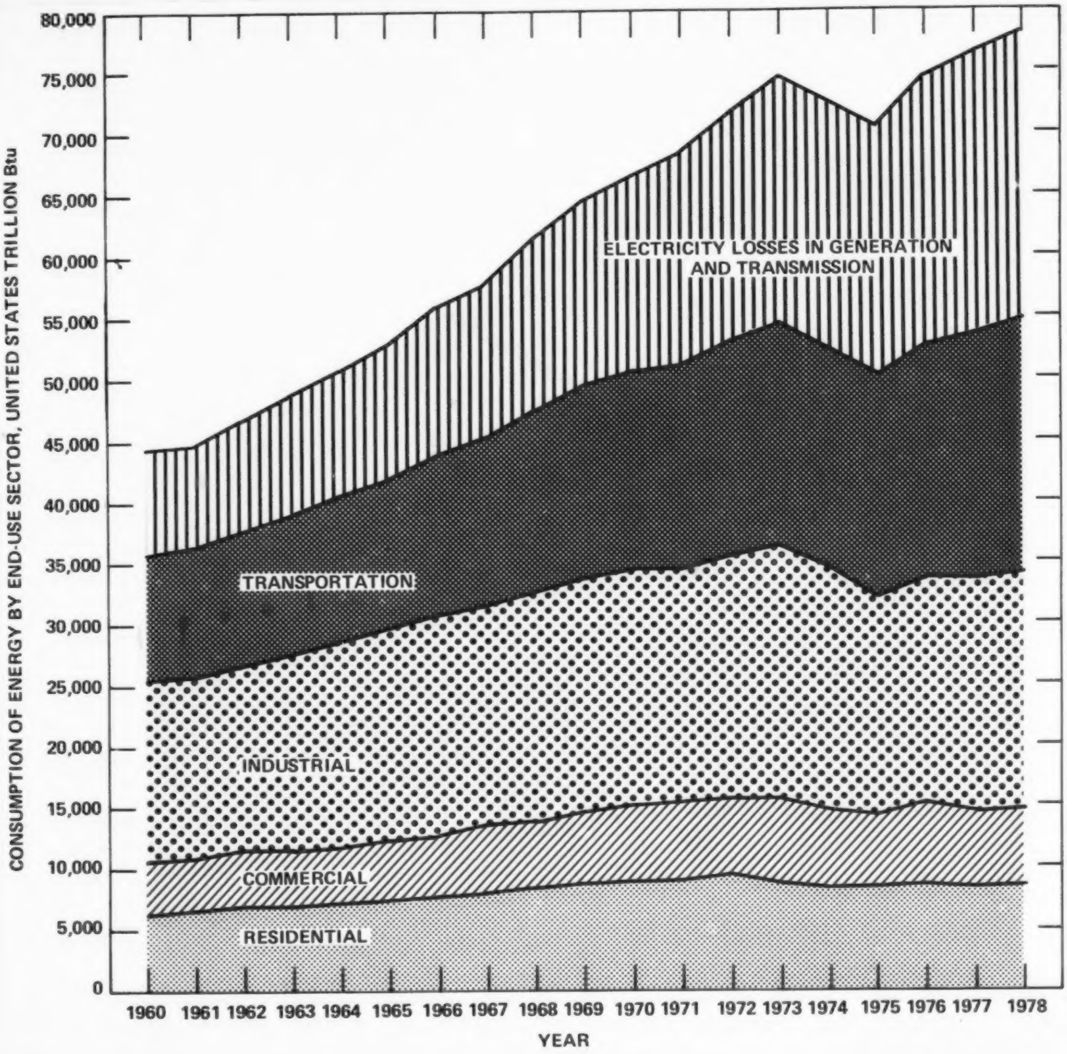


Figure 6. Total end use energy consumption of major U.S. consuming sectors (2).

Energy Use by Industrial Category

Industries do not consume energy in the same way or to the same extent. There are, for example, significant energy demand and use differences between the food industry, with its heavy needs for process steam, and the primary metals industry, with its major needs for direct heat in a variety of furnaces, or between the primary metals industry and the construction industry, with the latter's dependence upon labor and mechanized equipment.

Figure 8 provides a more detailed perspective on these differences. The data presented here compare the relative shares of total energy consumption devoted to broad end use needs for six of the nine largest energy consumers in the industrial sector. The sharpest differences lie in the allocations of

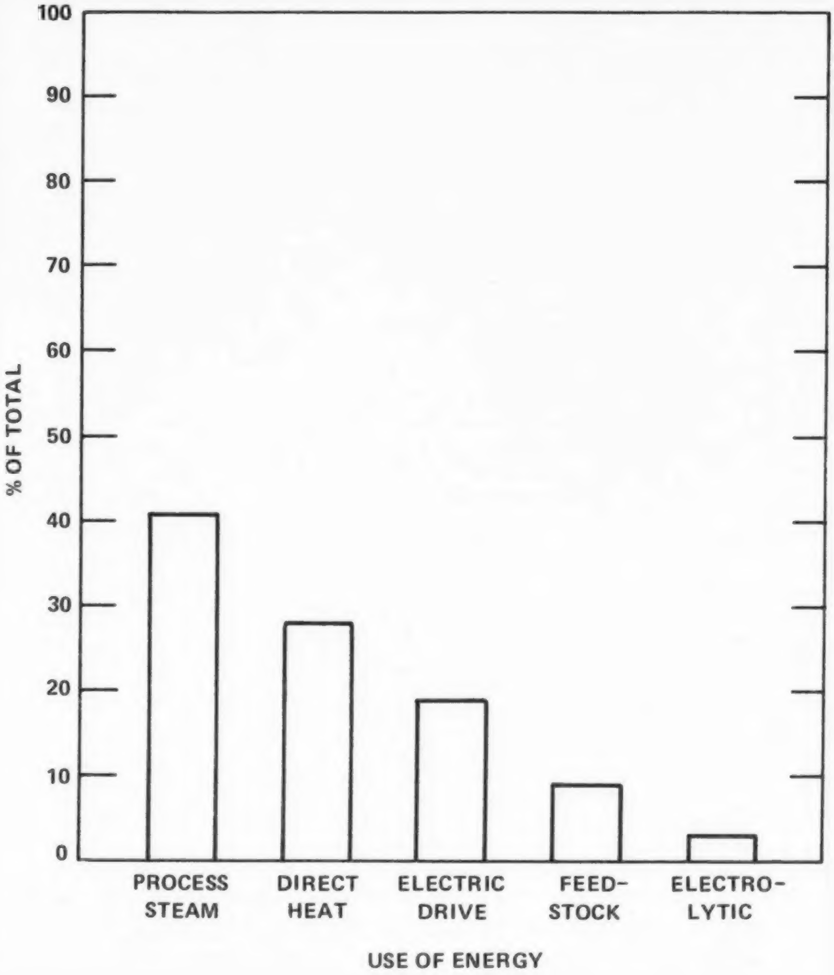


Figure 7. End uses of energy in the U.S. industrial sector (1974) (3).

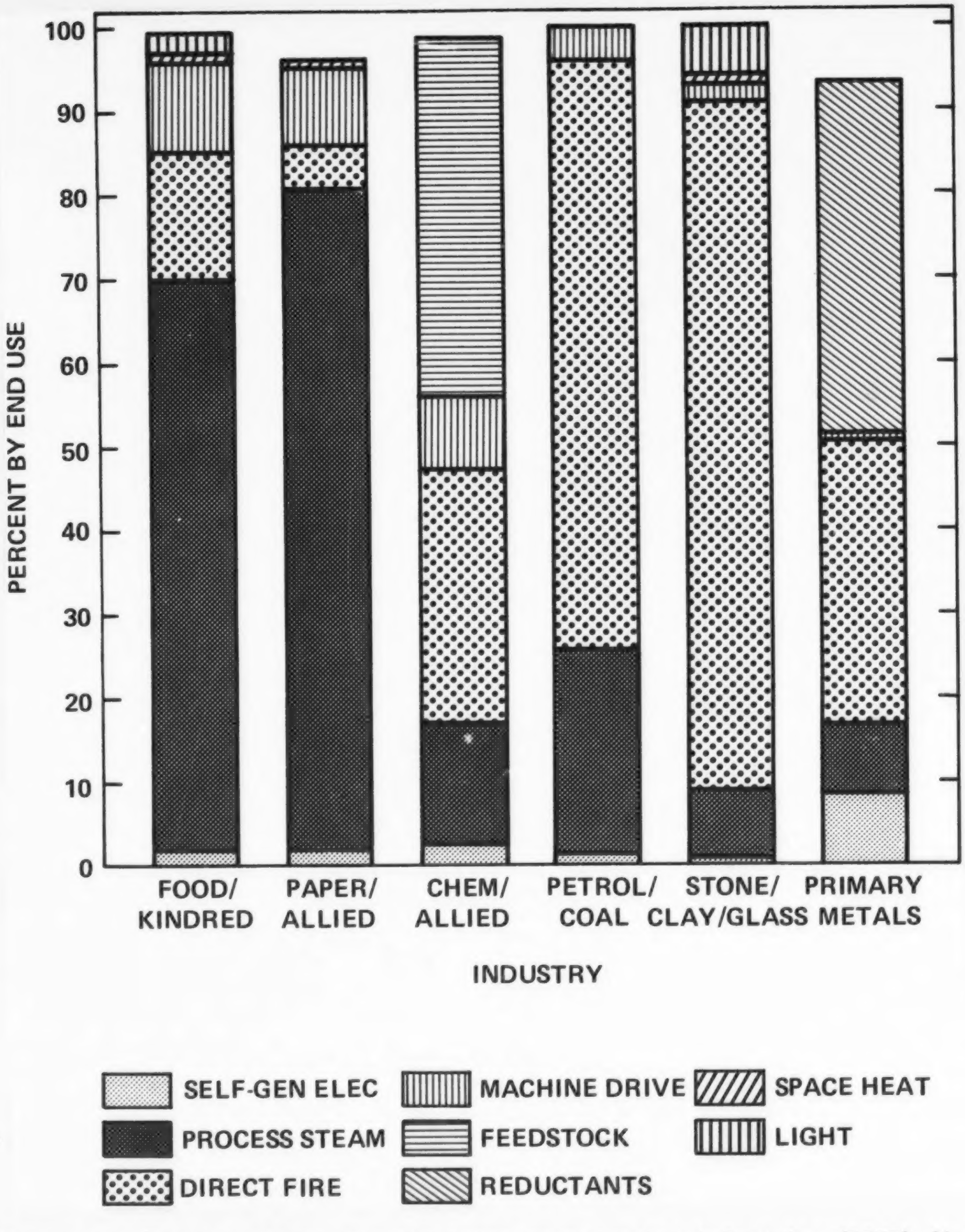


Figure 8. End use shares for six large energy-using industries (1977) (4,5).

energy to process steam and direct-firing applications. Some of these patterns are quite different from the aggregate picture presented in Figure 7.

A recent National Academy of Sciences panel developed a systematic framework for looking at the extent and nature of energy use in the industrial sector (1). This distinguishes such energy use according to three categories:

1. Industries employing processes that change molecular structure: chemical/allied products, primary metals, paper/allied products.
2. Industries employing processes that change the state or configuration of materials: food/kindred products, stone/clay/glass, construction.
3. Industries employing processes that change the physical arrangement or location of materials: all other industries in SIC categories A to D.

Table 4 uses this classification format to summarize the relative shares of energy end use for various major industry types for a typical (1974) recent year. (There have been some significant changes, such as shifts in fuel uses and realization of greater efficiencies, since the rapid upward changes in energy prices after 1973. However, preliminary assessment of these changes indicates that the concentrated pattern of energy use presented here remains basically unaltered [6].) This table reveals an important pattern of concentration of energy end use in a few industry types. Just over 60 percent of total industrial end use is concentrated in four key industry groups making up the Type 1 category: paper/allied products, chemical/allied products, petroleum/coal products, and primary metals. And at that, there are very large relative users in this category itself, such as chemical/allied products and primary metals. By contrast, the nine industry groups comprising the Type 2 energy use category account for much less than this, only 35 percent of the industry total. Nevertheless, some individual members of this category are substantial consumers in their own right: agriculture, mining, construction, food/kindred products, and stone/clay/glass. However, the use of energy in boilers in agriculture, mining, and construction is negligible and they have been eliminated from this discussion. All the industries in the Type 3 category account for little over 4 percent of the industry total. An important additional point, discussed in more detail in another section of this chapter, is that the use of large boilers is concentrated (nearly 75 percent in fuel use terms) among six of the nine largest types of industrial energy consumers: paper/allied products, chemical/allied products, petroleum/coal products, primary metals, food/kindred products, and stone/clay/glass.

Trends in Fuel Use

The industrial sector remains a major consumer of predominant U.S. energy supplies, including coal (anthracite, bituminous, lignite), natural gas, petroleum (distillate fuel, jet fuel, kerosene, lubricants, motor gasoline, residual fuel), and electricity. Industry also consumes a significant amount of "other" fuels such as wood, bark, bagasse, process gas, and a wide variety of process by-products.

TABLE 4. SHARE OF TOTAL ENERGY END USE BY INDUSTRY TYPE (1974) (1, 4).

Industry	SIC code	% of Total	Total % of category
1. Industries employing processes that change molecular structure			
Paper/allied products	26	8.8	
Chemical/ allied products	28	20.6	
Petroleum/ coal products	29	12.1	
Primary metals	33	19.0	
Total			60.5
2. Industries employing processes that change the state of configuration of materials			
Agriculture	1-9	5.6	
Mining	10-14	7.6	
Construction	15-17	7.3	
Food/kindred products	20	3.7	
Textile mill products	22	1.3	
Stone/clay/glass	32	5.1	
Fabricated/metals	34	1.6	
Non-electrical machinery	35	1.4	
Transportation equipment	37	1.5	
Total			35.1
3. Industries employing processes that change the physical arrangement or location of materials			
All others in SIC A-D		4.4	4.4

Figure 9 illustrates industry-wide statistics for various fuels for the period 1960 through 1978. These statistics suggest that aggregate fuel use trends have changed to some extent over this period. In absolute terms, the amounts of oil, natural gas, and electricity used have increased every year since 1960. Over the same period, the amount of coal consumed has declined each year. From the standpoint of relative shares, coal has declined precipitously since the early 1960s: 28 percent in 1963, 16 percent in 1978. Natural gas's role increased annually through the early 1960s. The relative roles of petroleum and electricity have both grown significantly throughout the period, to 33 percent and 13 percent, respectively, in 1978. Interestingly, the growth trend toward a larger share for petroleum has not basically altered following the world oil price discontinuity of 1973 to 1974.

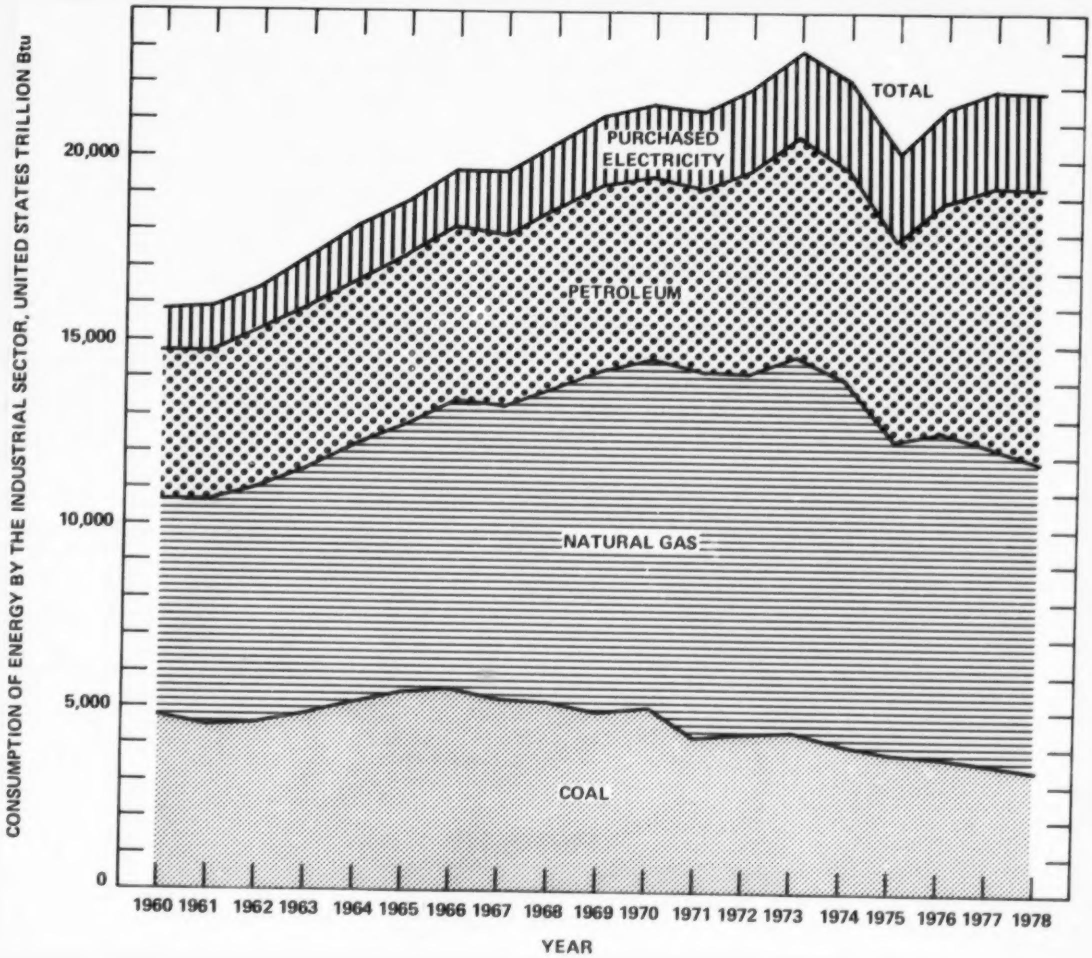


Figure 9. Total energy consumption by type in the industrial sector (2).

Two additional dimensions, however, need to be added to this aggregate picture of fuel use. The first relates to differences in fuel uses among industry types; the second, to characteristic locations of U.S. industry.

Regarding the former, there are some differences in the pattern of fuel use by major industry type. Figure 10 tabulates the relative shares of predominant fuels for the six large energy-consuming industries already listed in Figure 8. The roles of various fuels are widely different for each industry. The differences over the current roles for coal, natural gas, and "other" fuels are particularly pronounced.

Significant variations from the national aggregate picture become apparent as well when the geography of industrial energy use is considered. Not surprisingly, the demand for end use energy in the industrial sector is concentrated in the eastern/Gulf half of the U.S. In 1978, 49 percent of the total was consumed in the eastern U.S. (states east of a line formed by Michigan, Indiana, Kentucky, Tennessee, and Alabama). Twenty-nine percent was consumed in the Gulf states (Texas, Kansas, Oklahoma, Arkansas, Mississippi, and Louisiana). The remaining 22 percent was consumed in the western states, and 6 percent of that in California alone.

What is particularly significant is the extent to which the industrial end use is concentrated in only a few states. Just over 60 percent of the U.S. total in 1978 was consumed in ten large (>500 x 10^{12} Btu annually) industrial energy-consuming states: Alabama, California, Illinois, Indiana, Louisiana, Michigan, New York, Ohio, Pennsylvania, and Texas. Except for California, all of these are eastern or Gulf states. By and large, this pattern has not significantly changed for more than fifteen years.

Tables 5 and 6 provide details on current use levels and trends for total state/regional industrial energy use. In order to reduce the dimensionality of this information to manageable proportions, the information is reported for only two years in the period: 1963 and 1978. The reporting is also primarily in terms of U.S. regions (see Figure 1), though information for the ten large consuming states noted earlier is identified separately. Figure 11 maps the highlights of these statistics for both years.

With only a few noteworthy exceptions, the pattern of total energy consumption for the regions and large industrial energy-using states has changed little in the last fifteen years. As the figures in Table 5 indicate, the Great Lakes and Gulf Coast regions remain by far the largest consumers of industrial energy. Since 1973, the Gulf Coast has moved into first place. In contrast, the relative shares of the other regions have remained approximately the same over the period. Among the large industrial energy-using states, relative roles have remained nearly the same. One significant exception to this, however, is Louisiana, whose share of the national industrial energy total has nearly doubled (from 5.5 percent to 9.1 percent) since 1963.

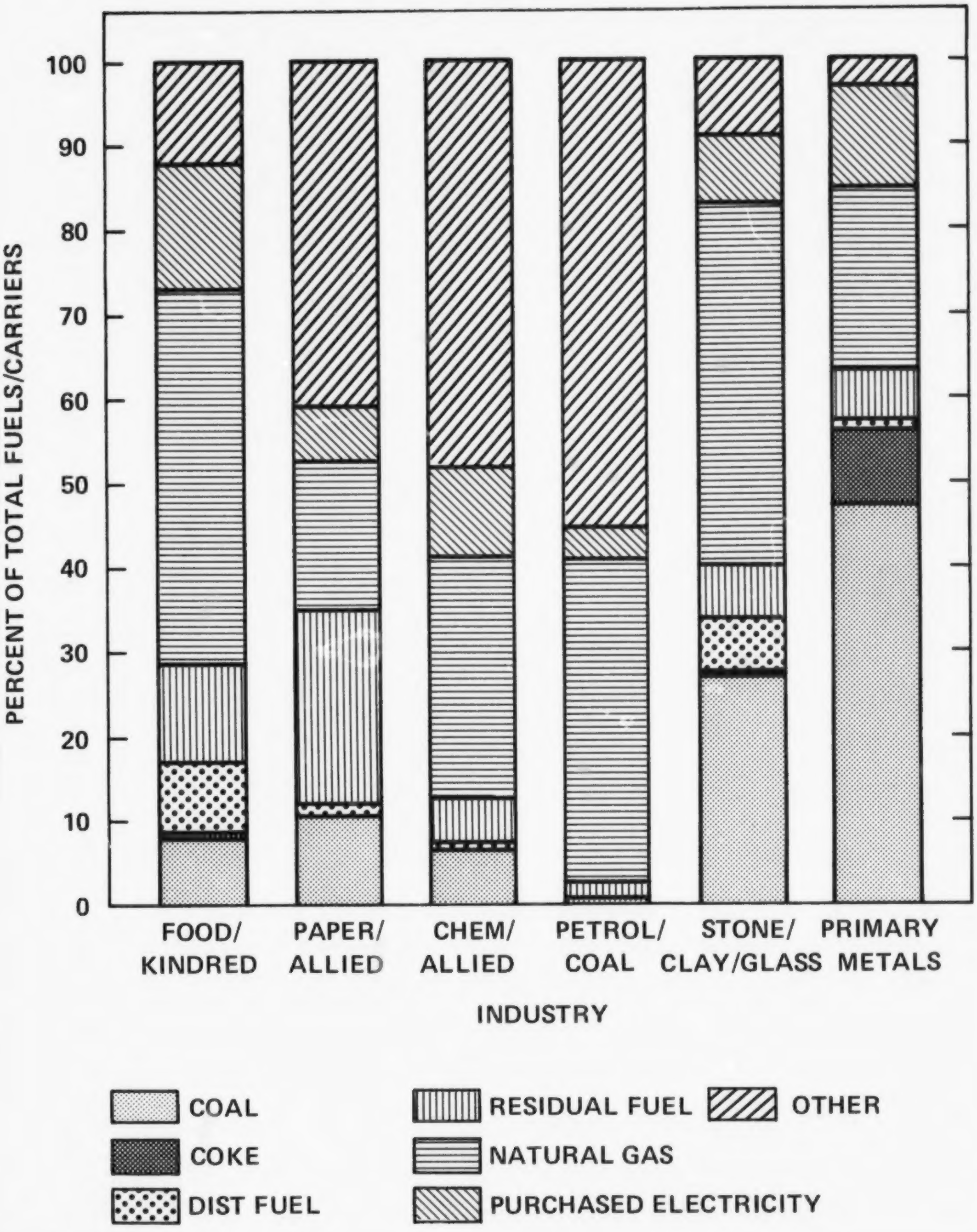


Figure 10. Share for predominant fuel types in six large energy-consuming industries (1977) (4,5).

TABLE 5. INDUSTRIAL END USE ENERGY CONSUMPTION IN REGIONS AND SELECTED STATES (1963 AND 1978) (2)

Region	State	1963 Total end use (10^{12} Btu)	1963 % of industrial total	1978 Total end use (10^{12} Btu)	1978 % of industrial total
New England		412	2.4	506	2.3
Upper Atlantic		1,386	8.0	1,259	5.7
	New York	693	4.0	616	2.8
Great Lakes		5,234	30.3	5,661	25.8
	Illinois	905	5.2	1,060	4.8
	Indiana	791	4.6	999	4.6
	Michigan	761	4.4	796	3.6
	Ohio	1,240	7.2	1,259	6.2
	Pennsylvania	1,537	8.9	1,441	6.6
Appalachia		1,614	9.4	1,950	8.9
	Alabama	386	2.2	578	2.6
Southeast		858	5.0	1,401	6.4
Gulf Coast		4,356	25.2	6,432	29.3
	Louisiana	941	5.5	1,986	9.1
	Texas	2,510	14.6	3,158	14.4
Great Plains		1,234	7.2	1,693	7.7
Rocky Mountain		467	2.7	678	3.1
Pacific Southwest		1,274	7.4	1,593	7.3
	California	1,000	5.8	1,244	5.7
Pacific Northwest		364	2.1	582	2.7
Totals		17,248	100.0	21,922	100.0

The trends in the relative roles for various fuels indicated in Table 6 for the industrial sectors in each region deserve some brief comments:

o Coal: Changes in roles differ between east and west. In the eastern regions of the U.S. (New England, Upper Atlantic, Great Lakes, Appalachia, Southeast) the role of coal has uniformly dropped since 1963, sometimes dramatically, by 20 percentage points or more. This area includes all the large industrial energy-using states except Louisiana, Texas, and California. In the Gulf Coast region, the share of coal is up somewhat, but still totals no more than a percent or so. In the Rocky Mountain, Pacific Southwest (including California), and Pacific Northwest areas it has

TABLE 6. INDUSTRIAL FUEL CONSUMPTION IN REGIONS AND SELECTED STATES (1963 AND 1978) (2)

Region	State	% of State/regional total							
		Coal		Natural gas		Petroleum		Purchased electricity	
		1963	1978	1963	1978	1963	1978	1963	1978
New England		14.2	0.5	6.9	10.3	65.0	71.8	13.9	17.5
Upper Atlantic		39.7	18.3	10.9	14.5	40.1	50.5	9.3	16.7
	New York	46.1	21.9	11.4	15.0	32.1	47.7	10.5	15.3
Great Lakes		52.5	33.3	20.5	25.5	19.9	27.8	7.1	13.4
	Illinois	39.5	13.5	24.8	35.2	29.7	39.8	5.9	11.6
	Indiana	56.2	42.3	18.6	19.8	20.8	26.8	4.5	11.2
	Michigan	51.7	21.5	20.2	35.6	21.0	27.6	7.2	15.4
	Ohio	51.1	36.8	23.3	24.4	14.2	22.2	11.3	16.6
	Pennsylvania	59.8	44.8	16.8	17.8	18.0	25.3	5.4	12.1
Appalachia		46.6	32.6	21.9	20.0	15.4	29.2	16.1	18.2
	Alabama	46.3	36.2	29.1	23.4	14.7	24.1	9.9	16.4
Southeast		15.1	7.2	26.1	21.3	47.0	53.2	11.8	18.2
Gulf Coast		0.6	1.3	81.6	71.1	14.9	20.9	2.9	6.7
	Louisiana	0.0	0.2	89.9	84.6	8.4	11.7	1.8	3.6
	Texas	0.8	1.8	83.9	70.8	12.7	19.6	2.6	7.8
Great Plains		26.7	13.6	27.3	30.8	40.4	44.5	5.5	11.1
Rocky Mountain		20.7	21.4	43.6	31.6	30.2	36.9	5.4	10.2
Pacific Southwest		3.9	5.3	57.4	39.6	31.7	41.2	7.0	13.9
	California	4.7	5.5	55.0	39.8	33.4	40.4	7.0	14.2
Pacific Northwest		6.2	5.2	32.4	24.8	37.1	39.9	24.3	30.1

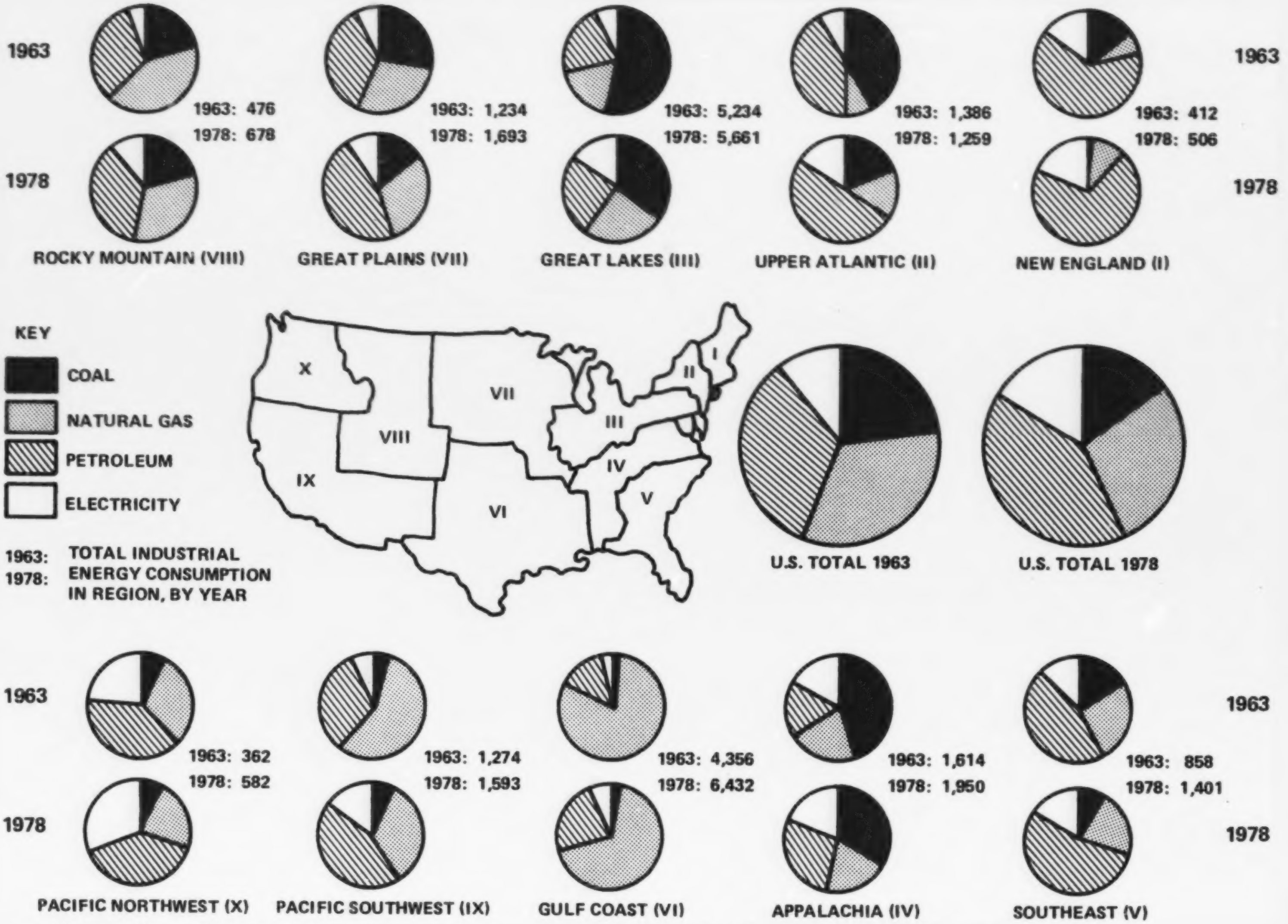


Figure 11. Industrial energy consumption by regions (1963 and 1978, 10^{12} Btu) (2).

remained largely unchanged. The Great Plains and Pacific Northwest regions are western exceptions in that coal's role there has declined significantly since 1963.

- Natural Gas: Role changes for this fuel are mixed--up and down, with small and large changes depending upon the region. Upward role changes (less than ten percentage points) occurred in the New England, Upper Atlantic, and Great Lakes regions from 1963 to 1978. Downward changes of a similar magnitude occurred over the same period for the Southeast, Great Plains, Rocky Mountain, and Pacific Northwest regions. The role of natural gas in Appalachia remained about the same. It was significantly down in the Pacific Southwest and significantly up in the Pacific Northwest.

- Petroleum: With only a few exceptions, this fuel's relative role rose from five to ten percentage points for all regions. It was significantly down in the Pacific Northwest region and up approximately 20 points in the Appalachian region.

- Electricity: The consumption of purchased electricity rose from five to ten percentage points in every region except New England (3.6 percent) and Appalachia (2.1 percent).

Finally, the pattern of concentration of industrial energy use in a few regions and states can be seen from another perspective, namely, the concentrated location of typically large energy-using industries. Table 7 summarizes the share of U.S. total industrial and end use energy consumption in each region for the nine largest energy-using industry types identified in Table 4. From this vantage point some of the concentrations are even more striking:

- Chemical and allied products industries are spread throughout the U.S. But nearly 60 percent of this sector's energy consumption is in the Gulf Coast region. Another 20 percent is split between the Great Lakes and Appalachia.

- Primary metals, the second largest energy-consuming industry type, is spread throughout the U.S. But nearly 60 percent of the energy consumption of this sector is concentrated in the Great Lakes region. Another 27 percent is split almost equally among the Upper Atlantic, Appalachia, and Gulf Coast regions.

TABLE 7. REGIONAL SHARES OF INDUSTRIAL ENERGY USE (1977)

	Chemicals		Primary metals		Petroleum/coal		Paper		Stone/clay/glass		Food	
	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %
New England	8	<1	6	<1	1	<1	34	7	7	3	5	3
Upper Atlantic	21	6	30	9	12	6	6	4	10	12	6	10
Great Lakes	10	10	49	57	10	19	4	10	8	33	3	20
Appalachia	30	11	29	12	3	2	17	15	6	10	3	6
Southeast	15	4	2	<1	<1	<1	45	25	6	6	5	7
Gulf Coast	52	59	5	6	27	52	6	16	3	14	2	11
Great Plains	16	3	9	2	6	2	16	7	12	9	17	17
Rocky Mountain	3	<1	51	4	26	3	<1	<1	9	3	7	3
Pacific Southwest	12	3	15	4	35	13	6	3	10	9	9	9
Pacific Northwest	7	<1	27	4	9	2	37	12	3	2	6	5

- Petroleum/coal products, another very large energy consumer, are primarily situated in the Gulf Coast and Great Lakes regions, with 52 percent and 19 percent of these industries' total energy consumption in these respective regions. Another 13 percent is located in the Southeast.

- Paper and allied products industries tend to be concentrated near raw materials. This sector's energy consumption is spread across the U.S. But concentrations in the Southeast, Gulf Coast, Appalachia, and Pacific Northwest regions are 25 percent, 16 percent, 15 percent, and 12 percent, respectively.

- Construction is particularly large in the Great Lakes (33 percent). Another 26 percent is split between the Upper Atlantic and Gulf Coast regions.

- Food and kindred products industries occur in the highest concentration in the Great Lakes (20 percent), with nearly as much activity in the Great Plains (17 percent). Another 29 percent is split among the Upper Atlantic, Gulf Coast, and Pacific Southwest regions.

ROLE OF BOILERS

By the most recent tabulation there are 506,930 boilers in the industrial sector (7). These represent a total capacity of 3,107,444 x 10^6 Btu/ hr. The key features of the distribution of these boilers can be summarized as follows:

- In 1975, these boilers are estimated to have consumed approximately 6.1 Q Btu of fuel, approximately 30 percent of the total end use energy consumed in the industrial sector that year.

- In aggregate terms, 14 percent of this energy was used to generate electricity, 72 percent for process steam, and 14 percent for space heat.

- Most (91 percent) of these boilers are quite small (<10 x 10^6 Btu/hr). The boilers most affected by the national fuel and environmental legislation presented in Chapter 3, that is, larger boilers with design firing rates greater than 100 x 10^6 Btu/hr, constitute just over 1 percent of the total population. In terms of total capacity, however, this group represents 41 percent. And this group's share of total boiler fuel use is even higher.

- Natural gas is the predominant fuel in all industrial boilers, accounting for 46 percent of the total capacity; oil-firing accounts for 34 percent; and coal follows as a distant third with 20 percent.
- Very few of the boilers not currently using coal have been designed with the capacity to convert to coal in the future.
- Like industrial energy consumption, the use of fuels in large boilers is concentrated in a small number of industries. Seventy-two percent of this fuel use occurs in the Type 1, large energy-consuming industries.
- The consumption of fuel in large boilers is also geographically concentrated, following lines similar to those for industrial energy use. The greatest concentration is in the Gulf Coast region (38 percent), followed by the Great Lakes (20 percent), Southeast (13 percent), and Appalachia (10 percent) regions.
- With few exceptions, this fuel consumption in large boilers is located in areas where there are also substantial human populations.

The following parts of this chapter provide amplifications of these points.

Boiler Technologies

Basic differences in boiler technologies can be distinguished by fuel type, capacity size, heat transfer configuration, feed mechanism (for coal-fired boilers, primarily) and style of manufacture (7).

The current population of boilers is fueled by nearly all major fuels: natural gas, oil (distillate and residual fuels), and coal. "Other" fuels such as wood, bark, bagasse, process gas, and other by-product fuels are also used to some extent. Boilers come in a wide range of capacity sizes, from less than 1.5×10^6 Btu/hr to 1500×10^6 Btu/hr. The size of boiler has straightforward implications (modified by prevailing load factors) for the amount of fuel required and, subsequently, for the level of pollutants emitted.

Three basic heat transfer configurations predominate: cast iron, fire tube, and water tube. Water-tube boilers are currently available in a wide range of sizes. They are typically used to generate steam at high pressure and high temperature, and are able to do so with considerable efficiency.

Fire-tube boilers are typically smaller and work well only in situations where loads are relatively constant. Cast iron boilers are usually quite small, compared with these other two, but work well in a wide variety of situations and with fluctuating load levels. Coal-fired water-tube boilers come in several feed styles. Chief among these are pulverization, spreader-stoker, underfeed-stoker, and overfeed-stoker. Finally, industrial boilers can also be distinguished by style of manufacture: field-erected and packaged. Packaged boilers are usually simpler to install, coming with pre-designed characteristics to ensure a rapid match to a wide variety of industrial settings and needs. Field-erected boilers are usually designed and built to specific circumstances and, thus, typically require longer installation time and result in greater costs.

Three characteristics of boilers are particularly salient for assessing the potential for residual discharges and the economics of conversion and control (7). These are fuel type, capacity size, and heat transfer configuration. The descriptions provided in the following section are based primarily on the population distinctions these provide.

Distribution of Technologies, Capacity, and Fuel Use

Figure 12 portrays boiler capacity as a function of heat transfer configuration and number of units in each capacity range. Very small boilers (<10 x 10^6 Btu/hr) predominate in terms of number; large boilers (>100 x 10^6 Btu/hr) account for little more than 1 percent. However, the large boilers represent 41 percent of the total capacity. All the large boilers use water-tube heat transfer configurations; most of the small boilers are fire-tube and cast iron in configuration. The mid-size boilers (10 to 100 x 10^6 Btu/hr) are split fairly evenly between water-tube and fire-tube configurations; none of these is cast iron.

Coal-fired boilers represent only 20 percent of the total industrial boiler capacity (7). Most of this capacity is concentrated in the 10 to 500 x 10^6 Btu/hr range; that is, mid to large in size. Oil-fired boilers (distillate and residual) represent 34 percent of the total capacity, mostly in the 1.5 to 500 x 10^6 Btu/hr range, and especially in the 10 to 100 x 10^6 Btu/hr range. Natural-gas-fired boilers, which are widespread in nearly all the size categories and especially concentrated in the 10 to 500 x 10^6 Btu/hr range, account for 46 percent of the total capacity.

Overall, the greatest concentration of boiler capacity lies in the 10 to 500 x 10^6 Btu/hr size range. Nearly half of this capacity is natural-gas-fired.

The predominance of natural gas is even more notable from the standpoint of fuel use; natural gas fires 46 percent of total capacity, but accounts for 67 percent of total fuel use (7). No statistics are presented for the use of "other" fuels (wood, bark, bagasse, and by-product fuels) (7). Anecdotal information suggests that these are used rather substantially in some industries (paper/allied products) and in some regions (the Gulf Coast). Statistics from the National Environmental Data System (NEDS) confirm this and provide some estimate of magnitude (8). But, information on the use of

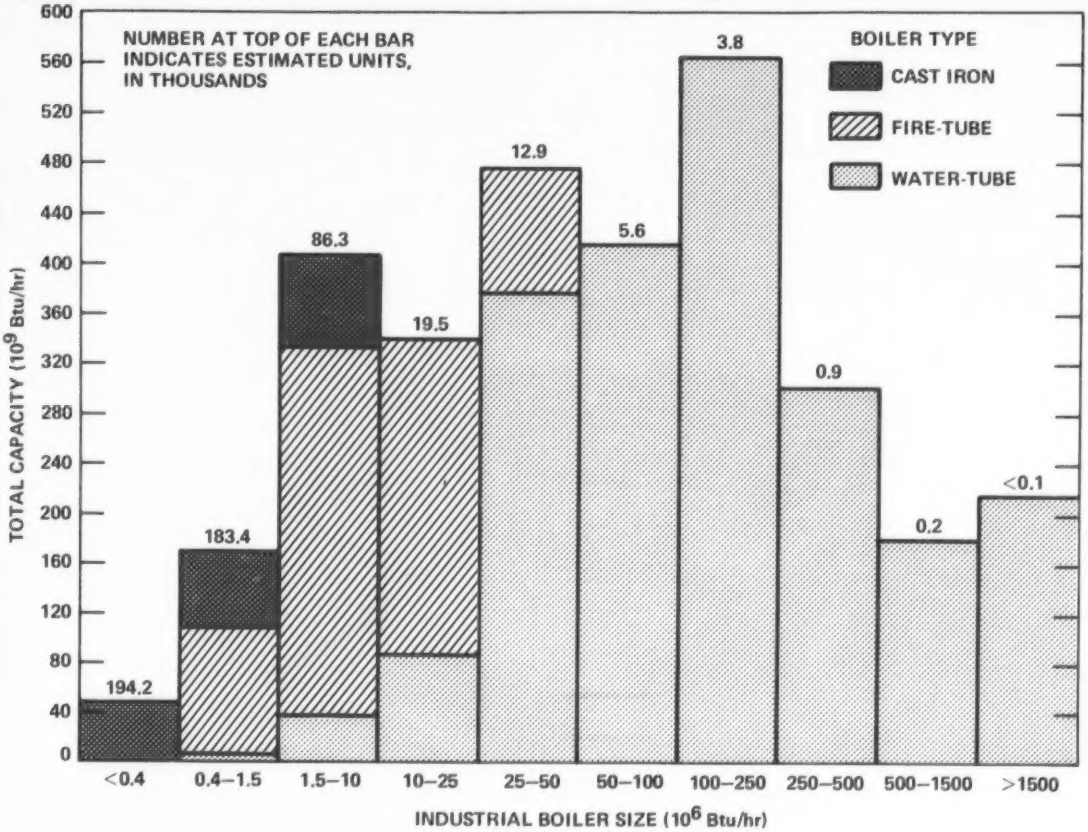


Figure 12. Size distribution of coal-fired industrial boilers by boiler type.

"other" fuels has not been sufficiently developed to provide reliable figures; Btu-equivalent transformations are also difficult. Nevertheless, this is an important gap in the picture presented here.

There are important geographic concentrations of industrial boilers and boiler fuel use. Tables 8, 9, and 10 provide statistics on the distributions of large boilers (>100 x 10^6 Btu/hr) and their fuel use by region. An indication of the adjacency of these to human populations is also given. Reliable information is not currently available to extend this regionalization to smaller boilers (7,8). This is, however, not a major barrier to the purposes of this report. Information presented in the remaining chapters provides evidence that, as far as fuel conversion and environmental control issues are concerned, the large-sized boilers are by far the most important. Figure 13 maps the highlights of Tables 8 and 9 for the U.S. as a whole.

The predominance of natural gas--at least among the large boilers reported here--is not as sharply defined when the regions are taken into account. There are regions where its relative fraction is very large, for

TABLE 8. REGIONAL DISTRIBUTION OF LARGE INDUSTRIAL BOILERS (>100 x 10^6 Btu/hr) (8)

Region	All boilers		By fuel type, within region					
			Coal		Oil		Natural Gas	
	Total	% of U.S.	Number	% of Region	Number	% of Region	Number	% of Region
New England	179	4.0	3	1.7	158	88.3	18	10.0
Upper Atlantic	334	7.5	28	8.4	239	71.6	67	20.1
Great Lakes	1170	26.1	340	29.1	422	36.1	408	34.9
Appalachia	642	14.3	206	32.1	253	39.4	183	28.5
Southeast	441	9.9	73	16.6	232	52.6	136	30.8
Gulf Coast	805	18.0	14	1.7	238	29.6	553	68.7
Great Plains	356	8.0	103	28.9	107	30.1	146	41.0
Rocky Mountain	81	1.8	14	17.3	22	27.2	45	55.6
Pacific Southwest	277	6.2	9	3.2	135	48.7	133	48.0
Pacific Northwest	146	3.3	16	11.0	86	58.9	44	30.1
Totals	4431	99.1	806		1892		1733	

TABLE 9. REGIONAL DISTRIBUTION OF FUEL USE IN LARGE INDUSTRIAL BOILERS (>100 x 10^6 Btu/hr) (8)

Region	All Fuels	Consumption by fuel type, within region (10^{12} Btu)		
		Coal	Oil	Natural Gas
New England	97	negl	94	2
Upper Atlantic	185	45	118	23
Great Lakes	737	316	168	253
Appalachia	388	189	112	87
Southeast	476	257	131	88
Gulf Coast	1421	36	173	1212
Great Plains	198	98	17	83
Rocky Mountain	47	14	2	30
Pacific Southwest	146	3	48	96
Pacific Northwest	62	12	25	26
Totals	3757	970	888	1900

NOTE: Intermediate totals may not fully agree, owing to rounding.

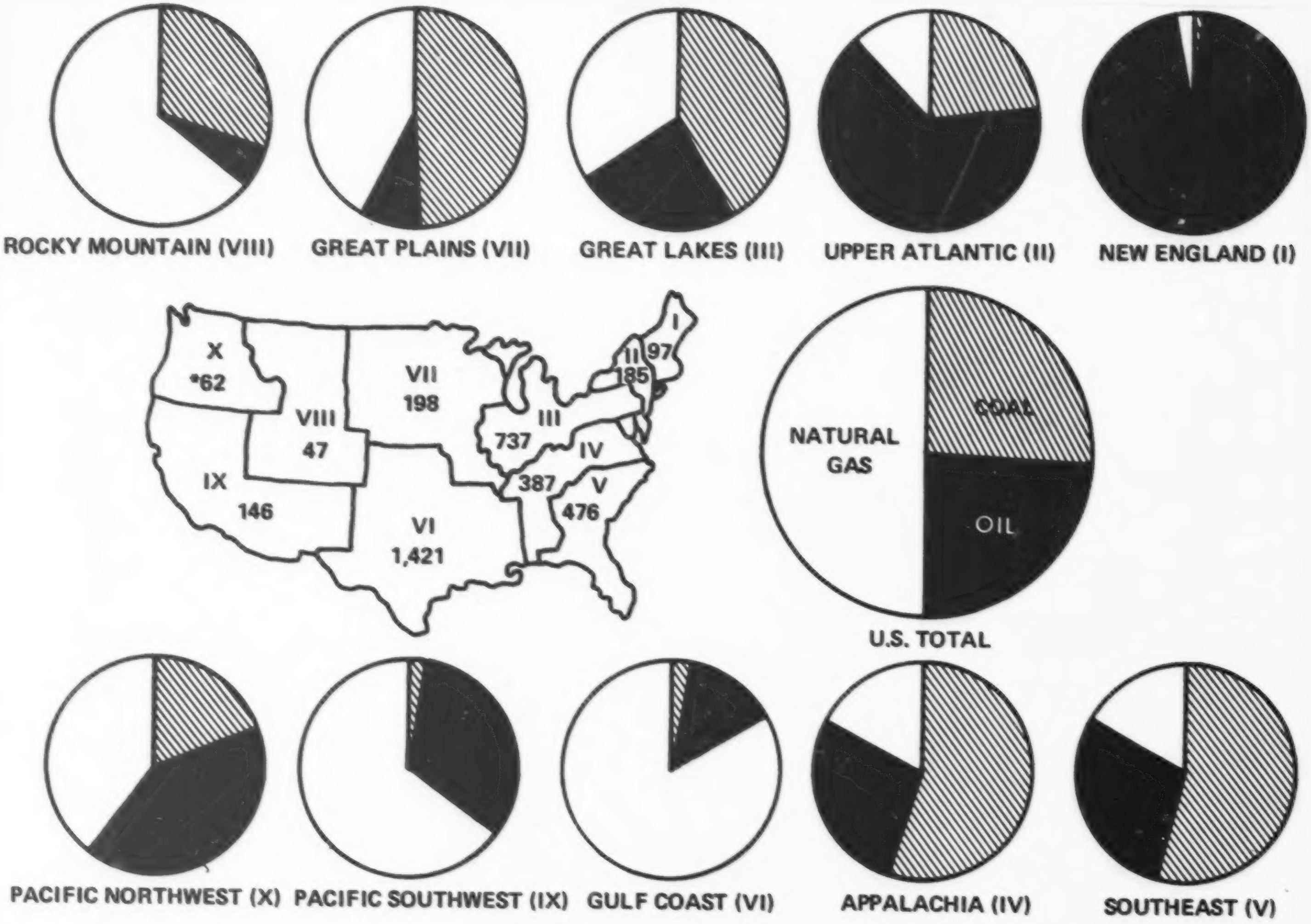
TABLE 10. THE ADJACENCY OF FUEL USE (x 10^{12} Btu) TO HUMAN POPULATIONS

Region	Urban	City	Rural
New England	6.1	85.4	11.6
Upper Atlantic	58.1	160.2	24.8
Great Lakes	214.5	585.2	151.8
Appalachia	77.6	230.1	157.9
Southeast	28.6	143.8	333.2
Gulf Coast	159.2	648.0	773.0
Great Plains	19.2	172.5	25.5
Rocky Mountain	15.3	26.7	20.3
Pacific Southwest	74.0	74.3	71.7
Pacific Northwest	7.2	47.7	14.3

NOTE: Urban was defined by county boundaries for 105 metropolitan areas nationwide with populations over 200,000. City was defined by the city limits for municipalities over 2500 in population. Urban may, therefore, be understood as a subset of the city category. Rural was defined as that remaining from the other two categories.

example, the Gulf Coast (85 percent), the Rocky Mountains (66 percent), and the Pacific Southwest (66 percent). But there are also regions where oil has the largest role, for example, New England (97 percent), the Upper Atlantic (64 percent), and the Pacific Northwest (74 percent); in some cases, coal already plays a more prominent role than the aggregate national statistics suggest. Coal meets 43 percent of the large boiler fuel needs in the Great Lakes, 49 percent in Appalachia, 54 percent in the Southeast, and 50 percent in the Great Plains (8).

Secondarily, as shown in Figure 14 by percentages and Table 10 by absolute fuel use, a great deal of the fuel consumed in the large boilers occurs in areas where human populations are fairly dense. Of all the regions considered, only the Pacific Southwest and the Gulf Coast had well over half of the total large boiler fuel consumed in rural locations. Of these, only the Gulf Coast region is a major energy consumer.



*KEY: REGION NUMBER – TOTAL FUEL CONSUMPTION (10^{12} BTU)

Figure 13. Regional fuel use of large industrial boilers (>100 x 10^6 Btu/hr) (8).

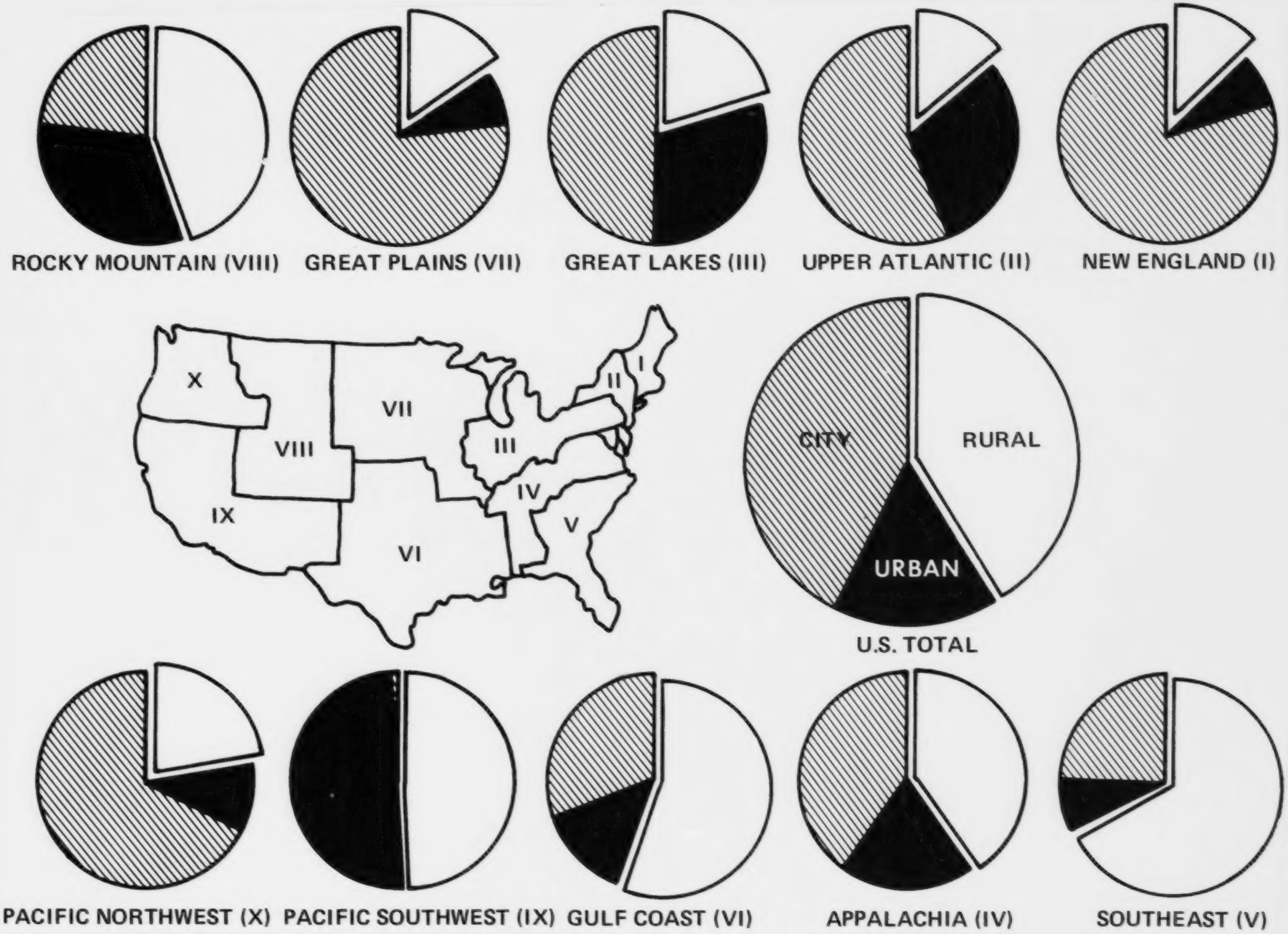


Figure 14. Fuel use in industrial boilers according to population density.

Siting patterns and regional concentrations of coal use both have implications for issues related to future coal-fired boiler conversions or growth. Among these are the environmental quality implications of modifications or additions to existing boiler capacity, human populations subject to added health and safety risks, competition for future industrial sites, the social costs and benefits of mandated boiler emission control technologies, and so on.

Finally, several additional features need to be discussed briefly to complete this overview of the distributional characteristics of the industrial boiler population.

Recently, many industries faced with installing new boilers have moved towards building a multi-fuel capacity into the boiler design. Many existing boilers can be adjusted fairly easily to use either oil or natural gas, or related gaseous and liquid fuels. But very few of these have the capability of shifting to coal. Table 11 presents summary statistics on this, regionally, for the large boilers. As can be seen, few boilers are capable of using coal as an alternative fuel.

TABLE 11. NUMBER OF LARGE INDUSTRIAL BOILERS ($>100 \times 10^6$ Btu/hr) WITH CAPACITY TO USE COAL AS ALTERNATIVE FUEL (8,9).

Region	Number of large boilers	Number with capacity to use coal as alternative fuel
New England	179	12
Upper Atlantic	334	15
Great Lakes	1170	66
Appalachia	642	35
Southeast	441	30
Gulf Coast	805	2
Great Plains	356	14
Rocky Mountain	81	5
Pacific Southwest	277	0
Pacific Northwest	146	3
Totals	4431	182

Age is also an important characteristic of the boiler population. Boilers are typically long-term investments, with lifetimes of 30 to 50 years, depending upon the technology and demand circumstances. They are also major plant investment items that come under the influence of economic factors related to depreciation. Extensive data collection on the age characteristics of the current boiler population was not undertaken as a part of this study. However, Table 12 draws on the efforts of another recent study to provide a capsule view of this. This information leads one to conclude that the boiler population is "middle-aged" or older (greater than ten years of age). Boilers with coal-fired capacity are even older.

TABLE 12. ESTIMATES OF AGE DISTRIBUTIONS OF INDUSTRIAL BOILERS (ALL SIZES) (7)

Boiler Type	Total boiler capacity (10^6 Btu/hr) Old*	New*	% New
Coal	775,200	36,700	4.5
Residual oil	888,300	332,500	27.2
Distillate oil	296,500	137,100	31.6
Natural gas	1,440,100	568,500	28.3

*New represents capacity added between 1967 and 1977. Old was in place before this period.

It was noted earlier that "other"-fueled boilers constituted a substantial number of boilers in some areas of the U.S. Table 13 summarizes the information on this part of the boiler population. There are quite a few of these boilers--at least in comparison with the total number of large coal-, oil-, or natural—gas-fired boilers in each of these regions. Geographically, they are concentrated in the Great Lakes, Appalachia, Southeast, Gulf Coast, and Pacific Northwest regions. And like the large boiler population, with only a single regional exception (the Pacific Northwest), the greatest share is located in areas where there are significant human populations. But whether or not this adequately represents the true population of these boilers is a question that requires more detailed inquiry.

Boiler Use in Major Industries

The magnitude of boiler roles varies substantially by industry type, particularly the role for process steam. Thus, one suspects that boiler characteristics (for example, average size, fuel use, load factors) might also vary by industry type.

TABLE 13. "OTHER"-FIRED INDUSTRIAL BOILERS (8)

Region	Number of large boilers	"Other"-fired boilers				
		% Number	% of U.S.	% Urban	% City	% Rural
New England	179	106	3.0	4.7	54.7	45.3
Upper Atlantic	334	89	2.5	15.7	86.5	13.5
Great Lakes	1170	665	18.6	32.2	67.7	32.3
Appalachia	642	559	15.6	25.8	68.3	31.7
Southeast	441	470	13.1	11.7	59.6	40.4
Gulf Coast	805	626	17.5	11.7	61.2	38.8
Great Plains	356	245	6.8	10.2	79.2	20.8
Rocky Mountain	81	81	2.3	16.0	71.6	28.4
Pacific Southwest	277	225	6.3	24.9	46.2	53.8
Pacific Northwest	146	468	13.1	14.1	58.1	41.9

NOTE: "Other" fuels include wood, bark, bagasse, process gas, and other by-product fuels. For a definition of urban, city, and rural, see Table 10, p. 77.

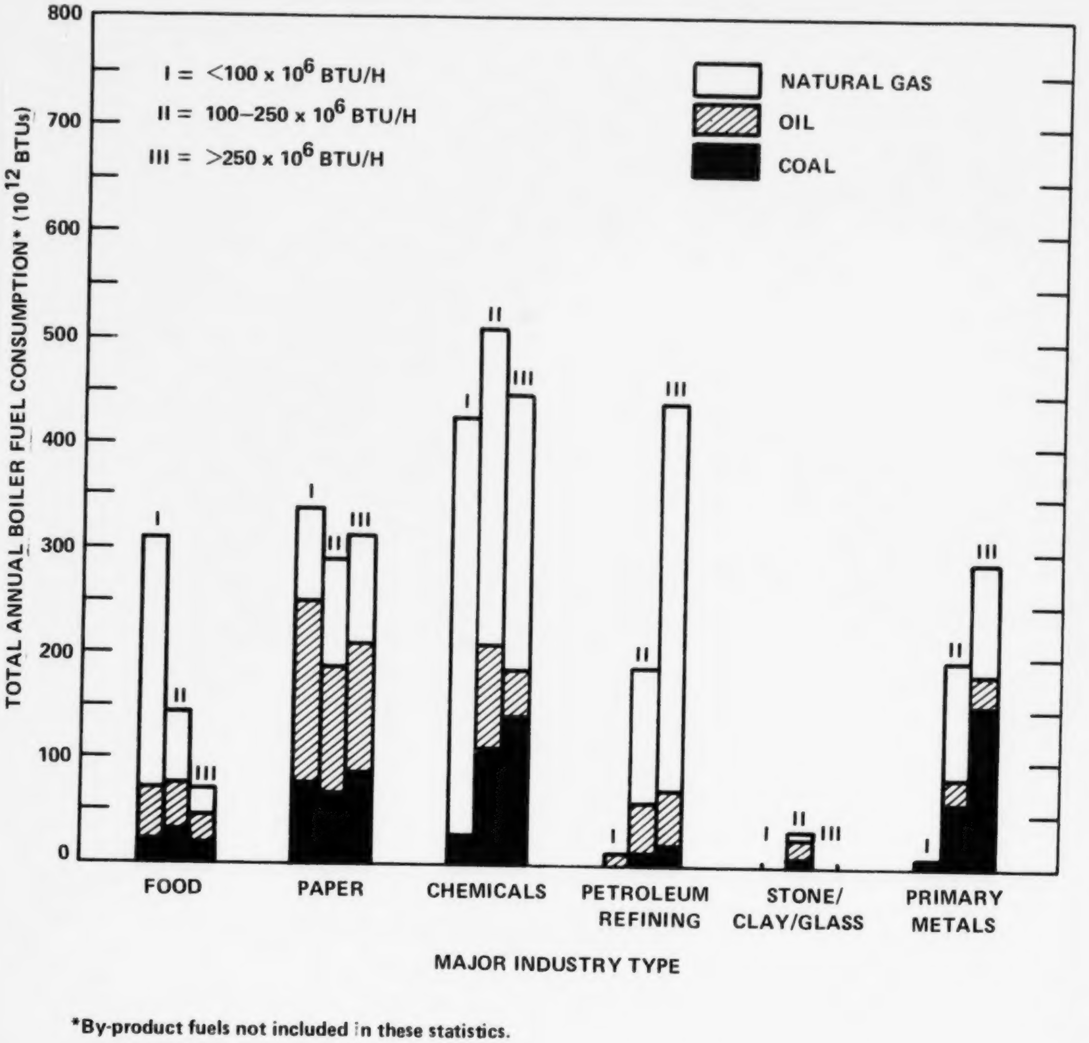
Table 14 provides a series of statistics that confirm this pattern. Information is presented on average boiler sizes, load factors, and large boiler fuel use shares for major members of the three industrial energy-using types already discussed (see also Table 4). This information repeats a familiar pattern of concentration. The large industrial energy users (the industries of Type 1) are, by and large, the users of the largest boilers. These boilers are typically used a large fraction of the time; load factors are nearly at or significantly above 50 percent (more details on load factors are discussed in Chapter 10). Total fuel consumption for the large boilers in the Type 1 industries constituted nearly 72 percent of the total U.S. boiler fuel consumption in 1974. Load factors and, particularly, the use of fuel in large boilers are quite a bit less for the Type 2 and 3 industries. However, care must be taken in drawing conclusions here since the statistical characterizations for these are not as complete.

TABLE 14. STATISTICS ON BOILER USE FOR THREE TYPES OF INDUSTRIAL ENERGY USERS (10,11,12)

Industry Sector	Av. boiler size (10^6 Btu/hr)	Av. load factor	% of total U.S. fuel use in large boilers
Type 1 Energy Consuming Industries:			
Paper	265	50	16.7
Chemical/allied	159	55	26.2
Primary metals	175	50	12.4
Type 2 Energy Consuming Industries:			
Food/kindred	102	45	5.4
Stone/clay/glass	ND	35	0.6
All others in Type 2	83	ND	9.9
Type 3 Energy Consuming Industries:			
All others in SIC A-D	74	ND	12.3

NOTE: ND = data not available.

Figure 15 provides an additional perspective. Here total annual boiler fuel use in the six largest energy-consuming manufacturers is presented according to three boiler capacity categories (<100 x 10^6 Btu/hr, 100 to 250 x 10^6 Btu/hr, and >250 x 10^6 Btu/hr). The fuel types for each of these categories are also listed (oil, coal, or natural gas--by-product fuels are not included).



*By-product fuels not included in these statistics.

Figure 15. Energy consumption by boiler size and fuel in six large energy-consuming industries.

A number of predominant characteristics can be seen from this. With the exception of the food/kindred products industry, large boilers (>100 x 10^6 Btu/hr) constitute the greatest share from the standpoint of total fossil fuel use. In some cases, this share is overwhelming (petroleum/coal products, and primary metals). Smaller boilers (<100 x 10^6 Btu/hr) play a significant role in several of these industries: paper/allied products, food/kindred products, and chemicals/allied products. It should be emphasized, however, that adequate data on the population of small boilers are not presently available. Thus, the relative contribution of small boilers may be substantially understated. The pattern of fossil fuel used is mixed. Natural gas and oil predominate throughout, but in most of the industries, coal is not insignificant.

RECOMMENDATIONS FOR FURTHER RESEARCH

We developed this energy use overview to see what the present pattern might tell us about the future. But one should not lose sight of the fact that the statistics presented in this chapter reflect historical energy circumstances that are quite different from those of the present. Chief among the differences is the continuing increase in the prices of previously inexpensive petroleum and natural gas. Another is the emergence of the regulatory power of environmental legislation, oriented, among other things, toward establishing emission standards and influencing decisions on industrial sitings.

Though they are not developed here, three areas, in particular, are likely to be quite influential in determining how the present pattern of industrial energy use could change in the future. They are worthy of further attention and research.

- Conservation. There have been substantial gains in the efficiency of energy use in all sectors of the U.S. economy since 1973-74. The potential for even more efficient fuel use in the future seems to have substantial technical backing. While the figures are not reported here, a careful analysis of growth trends in industrial energy demand for the large energy-using states during 1960 to 1973 and again for 1973 to 1978 reveals uniformly negative growth rate in the later period (with the exception of Louisiana) compared with uniformly positive rates in the earlier period. Whether or not this pattern will continue into the future is unknown. It is unclear which industries are likely to find conservation a technically feasible and economically attractive option. Nevertheless, this will clearly affect the patterns that emerge in the future.

- Choices of other fuels. The extent to which industries have short-term flexibility to use fuels that are either cheaper or in greater supply is unknown in any systematic way. Industries are likely to vary widely in this respect. Some have built multi-fuel capacities into their plants in recent years. But many have not. Over the long run, capital investments in new plants are theoretically possible, but some industries may be tied to processes that limit their effective fuel choices. The presence or absence of such flexibility will influence how energy use patterns change in the future.

- Location. There has been some speculation in the past that the regional pattern of industry might change over the next several decades as industries seek new locations in the south and southwestern U.S. Yet more recent analysis suggests that many of the advantages that would give such a change momentum (lower wage rates, less unionization, lower resource costs) have begun to erode since the 1970s. Some analysts now expect that the 1980s will see primarily intra-regional shifting of industrial locations. This could set off an intense competition among industries and other users for rural lands adjacent to urban areas and current industrial sites, and the future geographic pattern of industry (in energy terms) would look a good deal like the present. However, the added energy use in regions that are already large energy users would probably raise the issue of environmental quality control to a new significance. From this point of view, it will be quite significant whether the future pattern of industrial energy use is marked more by intra- or inter-regional shifts.

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CHAPTER 6

A COMPARISON OF BOILER TECHNOLOGIES

This chapter presents a framework and methodology for assessing air emissions, solid wastes, resource use, and aggregate costs that may result from increased use of coal in industrial boilers. New technologies for improving the discharges from coal-fired boilers are currently under development. EPA has sponsored a program of environmental assessments (EAs) that investigate these technologies--their effectiveness, their discharges, and their resource requirements. Unless otherwise noted, the information in this chapter was obtained from reports on the EAs, or from the project managers of the respective EPA contractors. (See also Appendix B.)

SCOPE AND ASSUMPTIONS

If coal use can be increased to the extent implied by the Fuel Use Act of 1978, 6 Q can be assumed as the energy content of coal used for industrial boilers in the year 2000. This value (and other levels of coal considered below for use in industrial boilers in 2000) is nominal. Actual levels of coal use will depend on the efficiency of the technology under consideration; in this analysis, what is kept constant is the heat content of steam produced. Such an increase in coal use will involve additions to the total inventory of boilers as well as replacement or retrofit of operating boilers that use other fuels.

The year 2000 energy demand of large industrial boilers (>100,000 lb of steam/hr) is based on a long-term economic forecast made jointly by the Office of Business Economics in the Department of Commerce and the Economic Research Service of the Department of Agriculture. These forecasts are known as the OBERS projections. OBERS forecasts at the level of major individual industries, and includes consideration of potential energy conservation, which generally falls into the range of 10 to 15 percent, depending on the industry's Standard Industrial Classification (SIC). After conservation has been accounted for, the increase in energy demand is assumed to be proportional to the projected economic growth (1). For this analysis, the growth forecasts, by industry, were applied to the present distribution of boilers to obtain projected regional distributions for new boiler capacity.

We assumed that 75 percent of new capacity gained in large boilers between 1980 and 2000 (or roughly 3.5 Q) will be fired by coal. Ninety percent of present oil-fired capacity in large boilers is assumed to be replaced by coal by the year 2000, with site-specific factors assumed to require 10 percent of new capacity to be fired by oil. For natural gas, 50 percent of existing capacity is assumed to be replaced by coal, with 15 percent of new capacity to be fired by natural gas. Further, an additional 0.7 Q of existing non-coal capacity in small boilers (<100,000 lb of steam/hr) is assumed to be replaced by large coal-fired boilers. Figure 16 summarizes the allocation scheme followed in the analysis. Note that new growth, replacement, and conversion translates into about 6 Q of coal-fired capacity in large boilers by the year 2000. A minimum of 3.5 Q of coal-fired capacity in the year 2000 also applies at existing industrial sites. Of the new growth to be coal-fired, much may also occur at existing facilities, since capacity additions may be expected in many industries. The assumed energy use for all fuels in 10^{12} Btu is shown in Table 15.

The assumed growth rates for coal are high, in our judgment, but certainly are within reason. Most importantly, however, the assumed fuel distribution in the year 2000 is consistent with the intent of the Fuel Use Act, and with the situation of greatly constrained oil supplies coupled with moderate industrial growth.

As previously noted, regional assignments of the year 2000 energy demand in industrial boilers are based on industry-specific growth projections from OBERS. Figure 16 documents the fuel use in 1978 and offers for comparison the

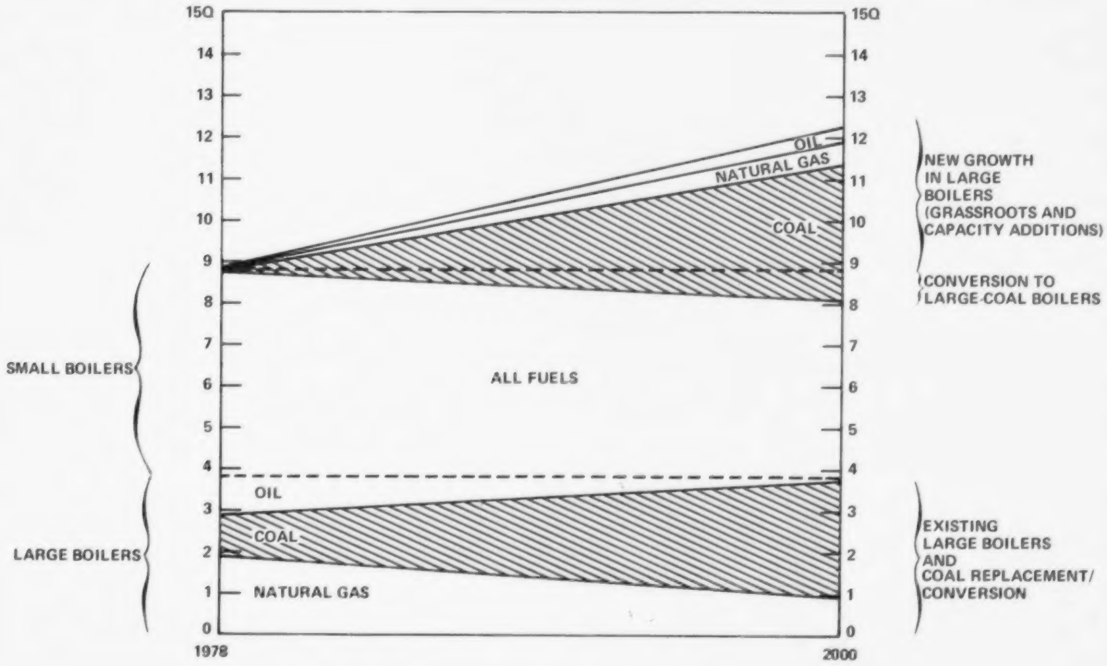

Figure 16. Summary of assumptions for industrial boilers.

TABLE 15. FUEL USE (x 10^{12} Btu) IN INDUSTRIAL BOILERS, 1978 and 2000

	Boiler size		
	<10^5 lb of steam/hr[a]	>10^5 lb of steam/hr	Total
	1978		
Coal	Negligible	1,000	1,000
Oil	1,250	900	2,150
Natural gas	3,750	1,900	5,650
Total	5,000	3,800	8,800
	2000		
Coal	Negligible	5,885	5,885
Oil	775	505	1,280
Natural gas	3,520	1,580	5,100
Total	4,295	7,970	12,265

[a] 100,000 lb of steam/hr is nominally equal to 125 x 10^6 Btu fuel input to the boiler.

resulting year 2000 fuel use levels for each region. Significant interregional shifts in energy demand can result from the differential growth rates of the SIC industries that now occur in various regions; however, no other provisions for regional migrations of industries have been assumed in the assignments. Further, the two typical coals used in the analysis were not uniformly applied to each region, since not all regions would have equal access to Western coal. In general, as shown in Figure 17, only Western coals are postulated to be used in the westernmost U.S. Coal use in the New England region is supplied entirely from Eastern coal, and the regions between these two extremes are supplied to varying degrees from both coal types.

Note that the consideration of coal use is restricted to the large boiler (>100,000 lb steam/hr) size range. First, adequate data for the present distribution of boilers only exist for the larger sizes. Second, as discussed in Chapter 10, the larger boilers are the most cost-effective size for using coal.

TABLE 16. PRIMARY FUEL DEMAND (x 10^{12} Btu) IN INDUSTRIAL MAJOR SOURCE BOILERS, 1978 AND 2000.

Region	Year 1978[a]				Year 2000[b]			
	Coal	Natural gas	Oil	Total	Coal	Natural gas	Oil	Total
New England	0.2	2.5	93.9	96.6	163.6	16.8	19.7	200.1
Upper Atlantic	48.8	22.7	117.6	189.1	321.5	42.5	32.5	396.5
Great Lakes	330.0	253.5	167.7	751.2	1242.3	253.7	101.4	1597.4
Appalachia	189.3	86.8	111.8	387.9	673.0	111.3	56.5	840.8
Southeast	257.0	87.6	131.1	475.7	878.9	135.8	74.5	1089.2
Gulf Coast	36.2	1212.6	172.7	1421.4	1902.2	827.2	164.5	2893.9
Great Plains	98.7	82.9	16.8	198.4	314.3	73.2	22.9	410.5
Rocky Mountain	20.9	30.5	2.3	53.7	77.1	23.0	5.4	105.6
Pacific Southwest	2.6	95.5	47.6	145.7	215.3	72.2	21.0	308.6
Pacific Northwest	11.7	25.5	25.2	62.4	97.4	22.8	9.2	129.4
Total	997.8	1902.2	899.8	3782.0	5885.7	1578.5	507.7	7971.9

[a] From reference 2.

[b] See text for assumptions. These amounts are the "baseline" for the reference mix (see text). Amounts for the other technology mixes will vary slightly because of efficiency differences.

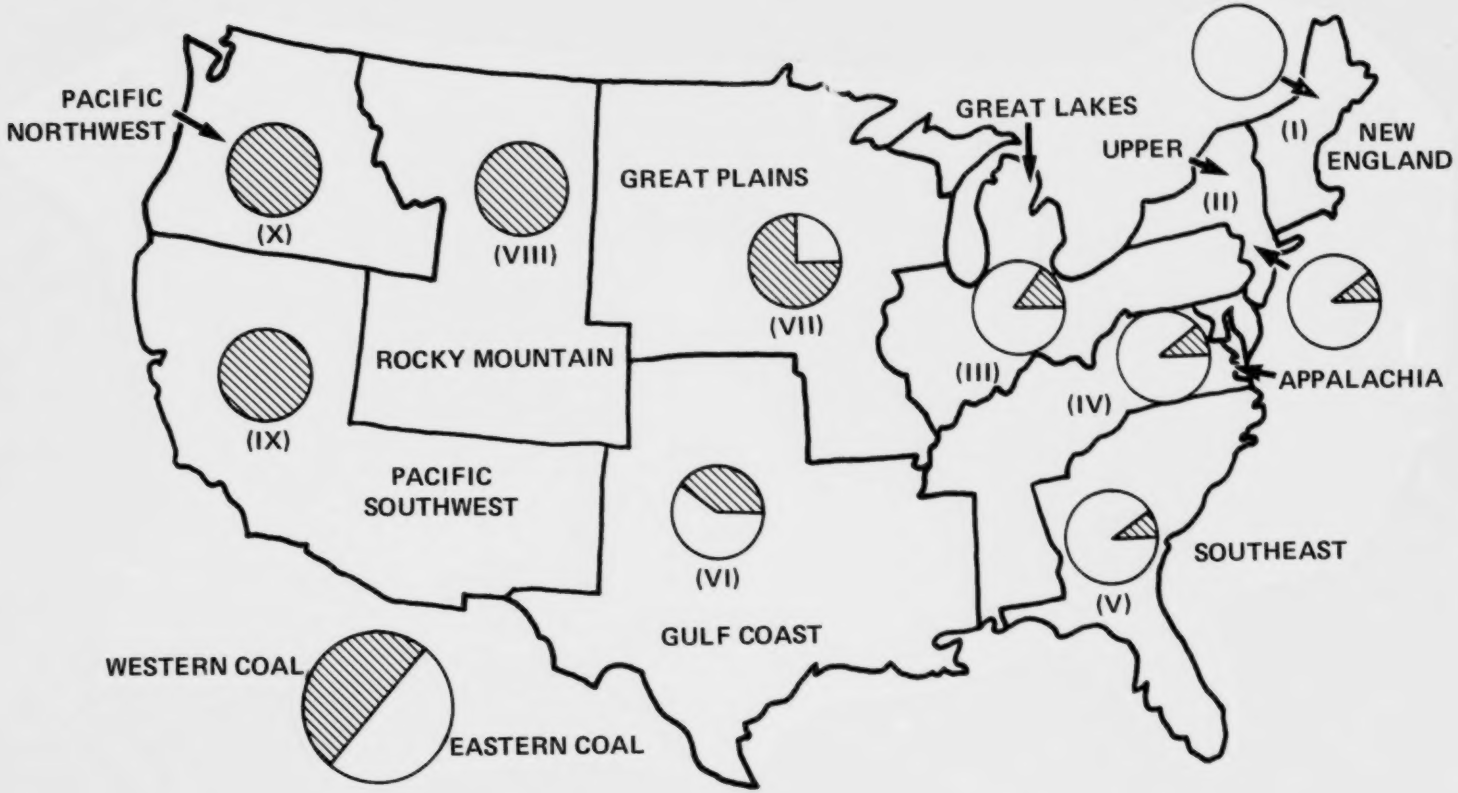
PACIFIC NORTHWEST
(X)
(VIII)
GREAT PLAINS
(VII)
GREAT LAKES
UPPER
(II)
(I)
NEW ENGLAND
(III)
(IV)
APPALACHIA
ROCKY MOUNTAIN
(IX)
PACIFIC SOUTHWEST
(VI)
GULF COAST
(V)
SOUTHEAST
WESTERN COAL
EASTERN COAL

Figure 17. Assumed year 2000 coal-use ratios for industrial boilers (Btu basis).

Our assumptions, however, do account for a slight reduction in capacity in the smaller boilers, consistent with a scenario emphasizing a greater role for coal. Overall, energy use in all industrial boilers is assumed to increase at a rate of 1.5 percent per annum between 1978 and 2000, and energy use in large boilers, at a rate of 3.4 percent per annum. The use of coal in large boilers is assumed to increase at 8.4 percent per annum. Coal use as a result of new growth increases at about a 4.4 percent per annum rate; conversion to and replacement of existing boilers to coal is estimated at a rate of 4.8 percent per annum. For a given coal type in a given region, the assignment of the coal technologies is kept uniform.

The latter point, in our opinion, represents a flaw in the regional assignments of technologies in the various technology mixes investigated. Intuition would indicate that some technologies may be favored more in some regions than in others. However, at present, we have no analytical basis for formulating such variations. Efforts presently underway within other portions of the Coal Technology Assessment program are developing the rationales and methods for relating differences in regions to differences in technology choice.

THE TECHNOLOGIES TO BE COMPARED

The technologies to be considered and compared in this document are the following:

1. Conventional combustion (CC)
2. Conventional combustion of physically cleaned coal (CC-PCC)
3. Conventional combustion with flue-gas desulfurization (CC-FGD)
4. Conventional combustion of physically cleaned coal with flue-gas desulfurization (CC-PCC-FGD)
5. Fluidized-bed combustion (FBC)
6. Fluidized-bed combustion of physically cleaned coal (FBC-PCC)
7. Low-Btu gasification with gas burned in boiler.

A conventional spreader-stoker water-tube boiler producing 100,000 lb/hr of steam (equivalent to a fuel input of 125×10^6 Btu/hr) operating at a load factor of 45 percent was selected as the basis for comparison. That size is representative of most coal-fired industrial boilers that have been installed in the last seven years. In fact, the size is close to average for all coal-fired water-tube boilers now in operation, as well as for all fossil-fuel-fired water-tube boilers sold in the last seven years. Both populations have been estimated to have an average fuel input capacity of about 70 to 75 x 10^6 Btu/hr, with a range of about 25 x 10^6 Btu/hr to more than 1500 x 10^6 Btu/hr.

The characteristics of typical Eastern and Western coals being used in all studies supporting EPA's review of standards for industrial boilers were adopted for this study. They are as follows:

Parameter	Coal Type A (Eastern)	Coal Type B (Western)
Btu/lb	11,800	9,600
Percent sulfur	3.5	0.6
Percent ash	10.6	5.4

For Eastern coal (Coal Type A), all seven technologies are compared for quantities of waste discharged and resource requirements for the same levels of steam produced. For Western coal (Coal Type B), which has low sulfur content, only technologies 1, 3, 5, and 7, as noted above, are compared.

A specific system was selected to represent each technology. The technology was then defined in terms of that system and all ancillary operations that would be required. For each of the five generic technologies addressed below, a short description is offered outlining its operating parameters and commercial status, as well as a simplified schematic showing the major process steps involved.

Conventional Combustion

A spreader-stoker water-tube boiler was selected to represent the conventional combustion technology. The module includes coal grinding and sizing that may be necessary, particulate removal systems operating at an assumed efficiency of 99 percent, and ash handling and disposal.

A water-tube boiler consists of a furnace in which the fuel is burned, generating hot gases that contact tubes, which then transfer heat to the boiler water and steam inside the tubes. Figure 18 is a simplified representation of the process. Depending on design, the tubes themselves may occur in various orientations within the furnace: vertical, vertically inclined, horizontal, or combinations of these. The boiler generates high-temperature and high-pressure steam. Boilers come in a wide range of sizes, and may be either "packaged" (constructed in a factory, then shipped to the site for use) or field-erected. The 100,000 lb of steam per hour size used as the baseline in this report is field-erected. Its primary thermal energy efficiency is 82 percent for both of the typical coals employed in the analysis. However, because of the lower heat content for the Western coal, the boilers firing this coal are slightly larger than the boiler firing Eastern coal for the same amount of delivered steam.

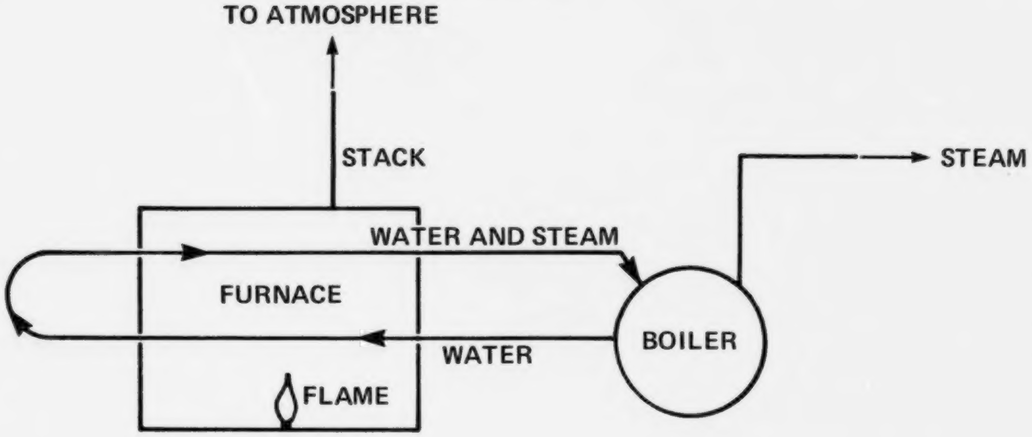

Figure 18. Water-tube boiler flow.

Spreader-stoking refers to the method of delivering coal to the furnace. This same method also provides a moving grate upon which the coal is burned. Frequently a return system is included for removing the bottom ash after combustion of the coal. Boilers with spreader-stokers have an upper size limit; past the size of boiler considered in this report, a pulverized coal-feed system is generally applied. The latter system operates on a different principle of suspension burning.

The major advantage of conventional water-tube boilers is that capital costs are less than for other coal technologies. They are currently widely used by industries burning coal, and they achieve generally higher thermal efficiencies than do most of the alternatives.

Flue-Gas Desulfurization

The double-alkali system is considered to be representative of FGD because a large percentage of systems now installed on industrial boilers are alkali throwaway systems. The module assumes 90 percent sulfur dioxide (SO_2) removal efficiency when raw coal is burned. With cleaned coal as the fuel, 90 percent overall removal is assumed; hence, a lower SO_2 removal is required in the scrubber stage. Corresponding reductions were assumed in sludge production, raw materials requirements, water requirements, and in capital and operating costs, when cleaned coal was burned. Particulate removal was assumed to occur ahead of the scrubber, with 99 percent overall efficiency. Figure 19 presents a simplified flow diagram for the sodium double-alkali system.

SO_2 scrubbing is a relatively weak acid-base reaction. In wet scrubbers without particulate collection, a slurry of alkaline sorbent with a cation component (in this case, sodium or Na^+) is allowed to settle downward through a tower of packed balls, shelves, or other obstructions, or is sprayed through an empty tower. Flue gas is blown by fans into the bottom of the tower, where the gas percolates upward through the slurry liquid and makeup water. The obstructions break up the bubbles, facilitating the slow reactions between the sorbent and sulfur in the flue gas. Pumps recirculate the scrubber slurry,

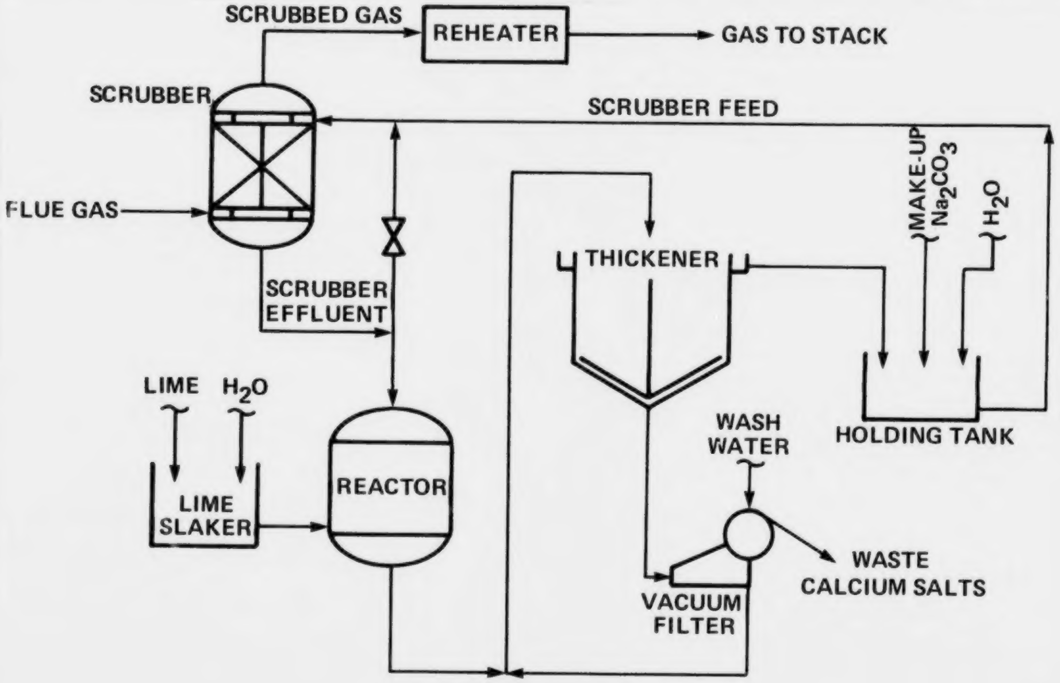
SCRUBBED GAS
REHEATER
GAS TO STACK
SCRUBBER
SCRUBBER FEED
MAKE-UP Na_2CO_3
H_2O
FLUE GAS
THICKENER
SCRUBBER EFFLUENT
LIME
H_2O
REACTOR
LIME SLAKER
WASH WATER
HOLDING TANK
WASTE CALCIUM SALTS
VACUUM FILTER

Figure 19. Sodium double-alkali process flow.

often with a bleedstream provided either to remove the absorbed sorbent for disposal ("non-regeneration") or to direct the used sorbent to other process steps for "regeneration." The "scrubbed" gas now leaving the scrubber may be reheated or blown out the stack by more fans. Other separation, oxidation, SO_2 conversion, pretreatment, drying, purging, or recirculation steps may be required, depending on the system used. Downward settling of sorbent slurry with flue gas bubbling upward is known as a countercurrent system; this is the predominant type (4).

The double-alkali system is a partial non-regenerative system of the countercurrent type. The system is partially non-regenerative because the sodium sorbent is regenerated in an additional process step that uses a lime/limestone reactant (or sorbent). The reactions in the regeneration step parallel those for the more common lime/limestone scrubber.

Advantages of the double-alkali system over other FGD systems are that the cost of the sodium sorbent is greatly decreased by regeneration, scrubbing efficiencies may reach 99 percent, and scaling problems in the scrubber system are decreased. Disadvantages, however, are production of wastes that include the soluble sodium species (although waste sludge amounts are comparable to the lime/limestone system), increased capital investment requirements, less allowable oxidation (the sodium sulfate thus produced is more difficult to regenerate), and a limitation to site-specific applications that satisfy both sodium and lime/limestone scrubber system requirements. In addition, double-alkali systems in the U.S. currently use only lime, though limestone systems are used in Japan and are under development in the U.S.

Scrubbing is an effective method of lowering SO_2 emissions. Only recently, however, has the technology been applied to industrial boilers. As of the first quarter in 1979, there were FGD systems operating at thirty-six industrial plants. The systems are commercially available, and some experience exists in operating scrubbers at industrial sites.

Unfortunately, flue-gas scrubbing exacerbates the general difficulties of using coal at industrial plants. Adding a scrubber results in some loss of thermal efficiency. (The efficiency of the double-alkali FGD unit on the previously described boiler is 80 percent overall.) As efficiency decreases, more coal must be mined, more transported, and more burned in order to produce the same net energy output. The sludge produced as a by-product of flue-gas scrubbing is difficult to handle and requires a large amount of land for disposal. Additional space is required to install the control unit itself, and this may necessitate relocating the entire steam plant. Scrubbers are noted for their technical complexity. Besides requiring skilled personnel to operate the unit, the inherent complexity of scrubbers adds to the maintenance requirements, and the probability of outages and downtime of the steaming system. The raw materials needed as sorbent in the FGD unit will consume additional storage space.

Flue-gas desulfurization is more disadvantageous with regard to facility size than most of the other coal technologies considered here. While cost as a function of size is not specifically analyzed in this study, the data provided by the Environmental Assessment contractor indicate that the cost of FGD rises rapidly at smaller facility sizes. The retrofit potential of FGD is determined in a large part by space limitations of the plant and by suitable access to the stack gas for treatment.

Physical Coal Cleaning

Coal can be physically cleaned to reduce the level of organic impurities and to remove the pyritic sulfur content. There are a number of techniques for cleaning coal. Current facilities, however, can remove only a portion of the sulfur, depending on the type of coal. The system chosen to represent this technology is a multistep process consisting of the following operations:

- Crushing and sizing of raw coal
- Separation of the 3-inch x 3/8-inch fraction by means of a jig or dense medium vessel (or cyclone) with mechanical dewatering
- Separation of the 3/8-inch x 28 mesh fraction in a dense medium cyclone with mechanical dewatering
- Separation of the 28 mesh x 0 fraction using hydrocyclones with mechanical dewatering, followed by thermal drying.

For Eastern coal (Coal Type A), the Btu recovery was assumed to be 91 percent, the weight recovery to be 79 percent, and the assumed sulfur content reduction to be 28 percent. The resulting analysis of the clean coal is 13,525 Btu/lb, 2.5 percent sulfur, and 5.7 percent ash. The uncontrolled SO_2 emissions from burning the cleaned coal would be 4.3 lb $SO_2/10^6$ Btu output (3.5 lb $SO_2/10^6$ Btu input), compared with 7.0 lb $SO_2/10^6$ Btu output (5.6 lb $SO_2/10^6$ Btu input) for the raw coal, a 39 percent reduction.

For Western coal (Coal Type B), the assumed Btu and weight recovery factors were 91 and 90 percent, respectively. A 28 percent reduction in the sulfur content was again assumed, giving 9700 Btu/lb, 0.43 percent sulfur, and 4.22 percent ash as the properties of the cleaned coal.

Coal cleaning is the most generally applicable of the technologies compared. It can be employed usefully in conjunction with any of the combustion processes, it can be used in existing equipment as well as new, and it can be employed in any size facility.

Physical coal cleaning offers substantial benefits in reducing maintenance requirements and in improving overall ease of boiler operations. The cleaning process removes many of the chemical species that adversely affect boiler performance. By removing more than 50 percent of the ash, the process lessens erosion problems and reduces proportionally the amount of land required for on-site solid waste disposal. Coal that has been subjected to physical cleaning also exhibits a more uniform chemical composition and a higher heating value. Uniformity of chemical composition improves combustion characteristics, while a higher heat content per unit weight lowers the transportation and storage requirements. Since treatment occurs at the mine rather than at the plant site, significant savings are attained in the amount of space that must be devoted to coal-related operations.

Although a substantial fraction of the original sulfur content is removed, the process does not achieve the high percentage reduction required for large utility boilers. Performance standards for smaller boilers are not yet promulgated, and should these standards approximate current regulations, physical coal cleaning alone will not consistently satisfy emission requirements for SO_2. Fuel costs will also be higher for cleaned coal. The price increase may, however, be offset by savings accrued from improved boiler operation and reduced transportation costs. Currently, cleaned coal is not uniformly available to all coal consumers. For example, some physical coal cleaning techniques provide a final product that often is not sized properly to be accommodated in some stoker-fed boilers. Sizing problems thus may limit the applicability of coal cleaning to only certain boiler designs.

Although the use of physical coal cleaning for sulfur oxide control has begun only recently, the process has been used for a long time to remove ash. Though figures are unavailable for the percent of cleaned coal used in industrial boilers, data are available for the amount used in the United States as a whole. As of 1975, there were 460 physical coal cleaning plants in operation, and these plants processed 58 percent of the total U.S. coal production of 588.6 million tons. Most of the cleaning plants are located in West Virginia, Pennsylvania, and Kentucky, all states where the coal is of high sulfur content. Ohio, Illinois, and Alabama also have a number of plants, with the remainder scattered throughout the western states of Colorado, New Mexico, Utah, Oklahoma, and Wyoming. Table 17 provides additional information about the current distribution of this technology.

The variability in sulfur content and washability of coal presents problems in the design of coal cleaning plants for optimal sulfur removal and Btu recovery. Research on this problem is in progress and more is needed to allow design of new coal cleaning plants that can achieve the optimal characteristics. Along with present physical coal cleaning plants, several new techniques are being developed that may be useful. These include two-stage froth flotation, oil agglomeration, high gradient magnetic separation, and heavy liquid separation. Each of these is at various stages of development. The first, two-stage froth flotation, is an elaboration of the single-stage process, which has been in use for some time. The two-stage process has been demonstrated in a pilot plant and soon may be installed in an existing coal cleaning plant. Oil agglomeration, which is based on a froth flotation-like process, has been used in a Canadian preparation plant. The third method, high gradient magnetic separation, uses magnetic forces to remove mineral components of the coal. As of yet, the technical feasibility of this process has not been well established, though research work is underway at Indiana University and MIT, the latter in conjunction with the General Electric Company. Heavy liquid separation is a process that employs a static bath of heavy liquid to separate clean coal, which floats, from its reject material. This process was developed thirty years ago. However, the liquids used in the past were expensive and produced toxic vapors. Otisca Industries has reported

TABLE 17. PHYSICAL COAL CLEANING PLANTS CATEGORIZED BY STATES FOR 1975 (5)

State	Estimated total coal production (1,000 tons)	Number of coal-cleaning plants	Number of plants reporting capacity data	Total daily capacity of reporting plants (tons)	Estimated annual capacity of reporting plants[a] (1,000 Tons)
Alabama	21,425	22	10	40,600	10,150
Arkansas	670	1	0	--	--
Colorado	8,168	2	0	--	--
Illinois	59,251	33	20	136,775	34,195
Indiana	24,922	7	6	42,000	10,500
Kansas	568	2	2	3,800	950
Kentucky	146,900	70	48	245,700	61,425
Maryland	2,792	1	0	--	--
Missouri	5,035	2	1	3,500	875
New Mexico	9,242	1	1	6,000	1,500
Ohio	44,582	18	13	102,750	25,690
Oklahoma	2,770	2	1	550	140
Pennsylvania (anthracite)	5,090	24	14	13,000	3,250
Pennsylvania (bituminous)	81,950	66	50	285,010	71,255
Tennessee	9,295	5	4	8,520	2,130
Utah	6,600	6	4	23,100	5,775
Virginia	36,500	42	29	143,550	35,890
Washington	3,700	2	1	20,000	5,000
West Virginia	110,000	152	113	577,375	144,345
Wyoming	23,595	1	1	600	150
Total	603,055	459	318	1,652,830	413,210

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[a] The estimated annual capacity values for the reporting plants were calculated from the daily capacity values by assuming an average plant operation of 250 days per year (5 days per week for 50 weeks per year).

recent breakthroughs in development of new liquids; this may change the feasibility of the process.

Fluidized-Bed Combustion (FBC)

This system is an atmospheric fluidized bed. The coal is dried on-site to about one percent moisture. Control of SO_2 at 90 percent removal is achieved with a calcium-to-sulfur ratio of 3.3 for Eastern coal. As with FGD, reductions in limestone requirements and in spent-bed production were assumed when cleaned coal was used as the fuel in FBC. A baghouse is employed to achieve particulate control to 0.038 lb/10^6 Btu.

Figure 20 is a simple schematic for fluidized-bed combustion (6). Coal and sorbent are fed simultaneously into the combustion chamber. The sorbent may be limestone, dolomite, or, perhaps in time, some artificial substance. As the coal burns in the chamber, SO_2 is released and reacts with the calcium oxide from the sorbent and with excess oxygen to form calcium sulfate. Air, which is injected from below the combustion chamber, keeps the coal and sorbent particles "fluid," dancing in a highly interactive bed. Fluidizing of coal and sorbent facilitates the SO_2 absorption reaction. Water tubes submerged directly in the fluidized bed maintain the operating temperature (750°C to 900°C) and provide for extremely effective heat transfer (7). Because combustion temperatures are relatively low, NO_x formation is also held to a minimum. Thus, emission control of SO_2 and NO_x is achieved in the combustion process itself.

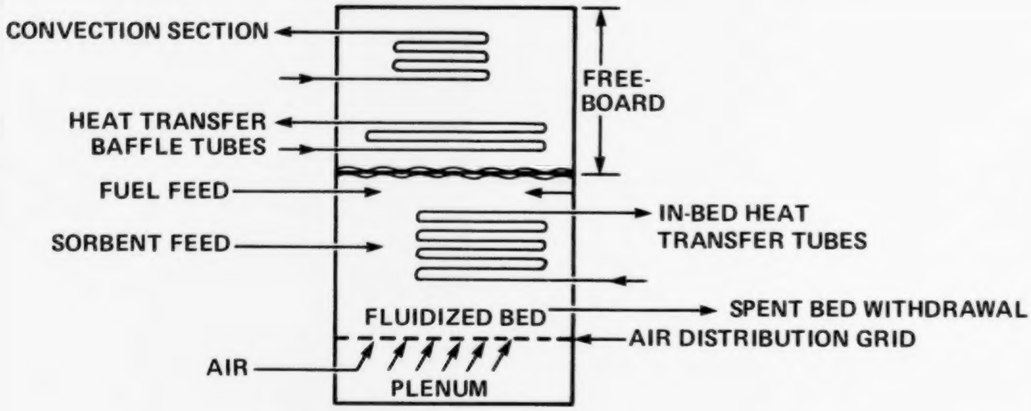
CONVECTION SECTION
FREE-BOARD
HEAT TRANSFER
BAFFLE TUBES
FUEL FEED
SORBENT FEED
IN-BED HEAT TRANSFER TUBES
FLUIDIZED BED
SPENT BED WITHDRAWAL
AIR DISTRIBUTION GRID
AIR
PLENUM

Figure 20. Typical industrial FBC boiler.

Fluidized-bed combustion achieves a high level of SO_2 removal. Since control is achieved in situ, that is, integral to the combustion process, and FBC units have advanced heat transfer design, efficiencies are maintained while sulfur emissions are effectively suppressed. (The thermal efficiency assumed for FBC in this analysis is 82 percent.) Another advantage of the efficient heat transfer characteristics of FBC units is that the boiler is only slightly larger than an equivalent capacity gas/oil boiler. The smaller size of FBC units lowers space requirements, and furthermore, allows the boilers to be delivered as a package. Simplicity of boiler operation and control, as well as fuel flexibility,* are other distinct advantages of employing fluidized-bed boilers for industrial steam production. Owing to their smaller size, FBC boilers are cost-competitive with conventional boilers (see Chapter 10).

Fluidized-bed combustion also has broad applicability. Units as small as 2.5×10^6 Btu/hr can be used and, with modular design, FBC is applicable to all boilers of industrial size. The modular design has the further advantage that modules for large facilities could be shop-constructed rather than field-erected. The question of the suitability of FBC for retrofit applications remains open. The Environmental Assessment contractor for this technology believes that the retrofit potential is low (see Appendix B). However, workers in Canada and Australia believe that FBC will be useful in retrofitting existing boilers. Ultimately, a case-by-case evaluation will be required for retrofit applications.

The major drawback of FBC is that it results in large quantities of solid waste. At the present stage of technical development, an extremely high sorbent/sulfur ratio must be employed to attain a 90 percent reduction in SO_2 emissions. The more sorbent required, the greater the amount of solid waste, and hence, the more land that must be available for disposal. Another impact of high sorbent requirements is that substantial quantities of limestone need to be supplied, handled, and stored at the plant site.

Fluidized-bed combustion is not presently used in any industrial facility, but appears to be a promising technology. As shown in Table 18, there are currently six industrial demonstration units, five industrial capacity test units, and seven pilot scale units operating or under construction. Of these seventeen units, fifteen are domestic, the largest number (four) of which are located in Ohio. Ohio has provided a favorable investment climate for development of FBC since the natural gas shortage of 1976. Largely, this is because in some instances, the state will provide financing under long-term tax-free bonds for FBC units.

The majority of the developmental units are financed by the U.S. Department of Energy, though private companies are currently operating some units. However, with DOE assistance, a number of the major manufacturers of conventional boilers are involved in FBC development, including Johnston Boiler Company, Foster-Wheeler, Babcock and Wilcox, and others. A 100,000 lb of steam per hour FBC demonstration unit is now operating at Georgetown University (see Table 18).

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*FBC boilers can generate steam from burning coal, sewage sludge, industrial wastes, wood wastes, gas, or oil.

TABLE 18. ATMOSPHERIC FBC DEMONSTRATION AND TEST UNITS

Developer	Capacity	Location	Sponsor	Status and comments
Demonstration Units				
Babcock and Wilcox Ltd. (England)	27,250 kg/hr steam	Central Ohio Psychiatric Hospital, Columbus, Ohio	Ohio Department of Energy	Currently operating
Babcock and Wilcox Ltd. (England)	45,400 kg/hr steam	Ohio State Penitentiary Columbus, Ohio	Ohio Department of Energy	Retrofit installation to be operational, 1981
Combustion Engineering	22,700 kg/hr steam	Great Lakes Naval Training Base, Illinois	U.S. Department of Energy	To be operational, 1981
Foster-Wheeler; Pope, Evans, and Robbins; Georgetown University	45,400 kg/hr steam	Georgetown University, Washington, D.C.	U.S. Department of Energy	Currently operating
Exxon Research and Engineering Co.	3-4 MW (10-15 x 10^6 Btu/hr)	Florham Park, New Jersey	U.S. Department of Energy	Unit is a process crude oil heater. In the testing phase
Johnston Boiler Co.	3 MW (10 x 10^6 Btu/hr) Thermal input	Johnston Boiler Co., Ferrysburg, Michigan	Private	Currently operating
Test Units				
Foster-Wheeler; and Pope, Evans, and Robbins	88 MW (220 x 10^6 Btu/hr) Thermal input	Rivesville, West Virginia	U.S. Department of Energy	Has been operational. May be shut down, 1981
Babcock and Wilcox Ltd. (England)	12 MW (40 x 10^6 Btu/hr) Thermal input	Renfrew, Scotland	Internatio[illegible] nergy Agency	Retrofit unit currently operating
Babcock and Wilcox Company (U.S.)	6 MW (20 x 10^6 Btu/hr) Thermal input	Alliance, Ohio	Electric Power Research Institute	Currently operating
Battelle Columbus Laboratories	7 MW (25 x 10^6 Btu/hr) Thermal input	Columbus, Ohio	U.S. Department of Energy	Under design
Morgantown Energy Research Center	18 MW (60 x 10^6 Btu/hr) Thermal input	Morgantown, West Virginia	U.S. Department of Energy	Currently operational for testing

TABLE 18. ATMOSPHERIC FBC DEMONSTRATION AND TEST UNITS (concluded)

Developer	Capacity	Location	Sponsor	Status and comments
Pilot Scale Test Units				
Combustion Engineering	1 MW (3 x 10^6 Btu/hr) Thermal input	Windsor, Connecticut	U.S. Department of Energy	Currently operating
Energy Resources Co.	1.8 MW (3 x 10^6 Btu/hr) Thermal input	Cambridge, Massachusetts	Private	Currently operating
Pope, Evans, and Robbins	1.5 MW (5 x 10^6 Btu/hr)	Alexandria, Virginia	U.S. Department of Energy	Currently operating
Stone, Platt Fluidfire, Ltd.	0.3 MW (1 x 10^6 Btu/hr) Thermal input	Virginia Polytechnic Institute, Blacksburg, Virginia	--	--
Mastad and Son (Gjovik, Norway)	25 MW (85 x 10^6 Btu/hr) Thermal input	Varmwerk (Heating Works), Enkoping, Sweden	--	Demonstration runs, 1980
Stal-Laval Turbine Company (Finspang, Sweden)	1.5 MW Thermal output	District Heating Plant, Orebro, Sweden	--	Currently operating
Babcock and Wilcox Company (U.S.)	55 MW Thermal input	Shawnee, Tennessee	Tennessee Valley Authority	In construction

Although there appears to be a clear commercial, industrial interest in this technology, it is also clear that there are several limiting technical problems to be solved. These include standardization of technical parameters and maintenance procedures, which are presently being examined. Once these have been dealt with, and FBC has been demonstrated as commercially feasible for industrial use, industries will undoubtedly utilize this technology in the near future.

Low-Btu Gasification

The system selected to represent this technology consists of a Wellman-Galusha gasifier and a Stretford acid-gas removal unit. The Wellman-Galusha is a fixed-bed, dry-ash gasifier, and the Stretford process is a direct conversion, liquid-phase oxidation system in which H_2S in the low-Btu gas is removed by adsorption, with subsequent oxidation of the sorbed H_2S to elemental sulfur. Additional operations included in the module are crushing and sizing of coal, quenching and scrubbing of raw gas prior to acid-gas removal, and steam boiler firing with the low-Btu gas. All pollutant discharges and resource requirements presented herein include those for both the gasification, with its auxiliary operations, and the steam boiler. Figure 21 displays the process.

The entire coal-to-steam process for low-Btu gasification may be best understood as four basic steps: 1) coal pretreatment; 2) coal gasification; 3) gas purification; and 4) combustion in a boiler similar to that used with natural gas. Figure 21 shows all but the first of these steps. A number of ancillary operations relating to pollution control also occur. Close to seventy different types of gasifiers have been used in the past or are now under development.

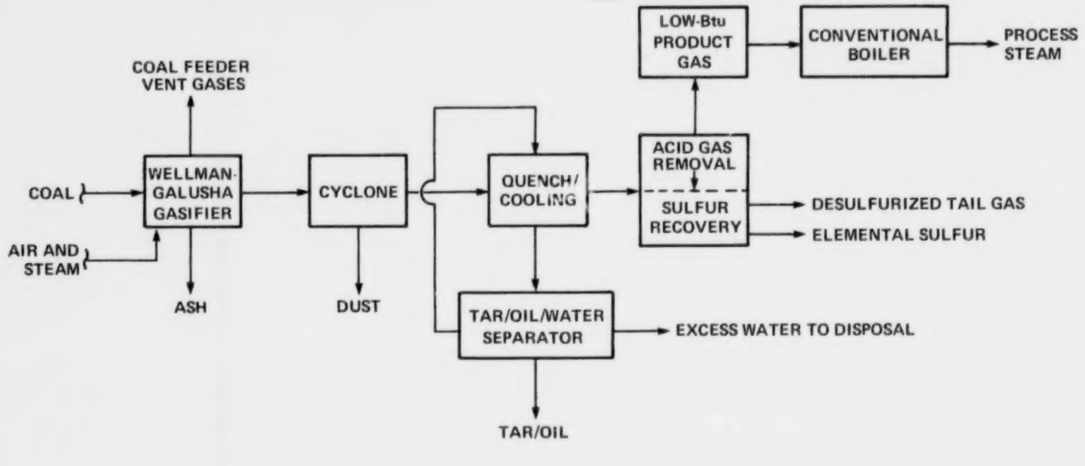
LOW-Btu PRODUCT GAS
CONVENTIONAL BOILER
PROCESS STEAM
COAL FEEDER VENT GASES
ACID GAS REMOVAL
COAL
WELLMAN-GALUSHA GASIFIER
CYCLONE
QUENCH/ COOLING
SULFUR RECOVERY
DESULFURIZED TAIL GAS
ELEMENTAL SULFUR
AIR AND STEAM
ASH
DUST
TAR/OIL/WATER SEPARATOR
EXCESS WATER TO DISPOSAL
TAR/OIL

Figure 21. Wellman-Galusha low-Btu gasification process.

Since coal is converted from a solid to a gaseous fuel, many of the technical difficulties of combustion are effectively overcome. The final product should be a very clean fuel that can be used for a boiler fuel, for direct heat applications, and in some instances, for a feedstock. Thus, for most industries, low-Btu gasification of coal would provide a single fuel capable of meeting nearly all of a plant's energy needs. The efficiency assumed for low-Btu gasification in our analysis is 54 percent with Eastern coal, and 57 percent with Western coal; these efficiencies are considerably lower than those of the other coal technologies under consideration.

One disadvantage of low-Btu gasification technologies is their capital costs. As will be shown in Chapter 10, low-Btu gasification is the most expensive technology studied in our project. Moreover, the cost penalty for low load factors makes potential applications much more problematic than would appear from technical considerations alone. A portion of the total capital cost, however, would be saved, since existing boilers would not necessarily have to be replaced.

A greater disadvantage, however, is the low overall efficiency of the system. For example, 65 percent more coal must be mined, transported, and consumed in the boiler to provide the same annual energy output provided by conventional or fluidized-bed combustion. Thus, logistical problems are greatly increased. One reason that the overall efficiency is so low is that the product fuel has a low heat content relative to volume. The lower heating value also means that the fuel can be economically used only at the point of production, since costs of transporting the gas through pipelines would be prohibitive. Therefore, all the necessary coal storage, handling, and preparation facilities must be located at the industrial plant site. Facilities for converting the coal into gas must also be on-site. Low-Btu gasifiers will be even more subject to space limitations than are the alternative technologies. The quantity of solid waste produced is less than that from FGD or FBC, but the residue is probably extremely hazardous and may present special disposal problems.

Low-Btu gasification technology is available commercially, yet only eleven units (representing three different types of processes) are presently operational in the U.S. (8). This pattern of low utilization holds on the worldwide level; 200 units have been built, but only twenty-five are in commercial operation. On the whole, there is much uncertainty about the use of low-Btu systems to meet industrial needs. Development is in its early stages, and the capability of the technology to produce clean fuels is promising but unclear. Research in progress on more advanced gasification systems holds promise for the development of lower-cost (and perhaps more efficient) systems.

DESCRIPTION OF METHODOLOGY

The discharges produced and the resources required by the selected technologies are compared in three ways at various times in later chapters of this report. First, individual technologies are directly compared as to their resource requirements, discharges, and costs. Second, a comparison can be made in which the discharges and resources are determined for "trajectories," each of which produces the same quantity of steam. In the third type of comparison, the total discharges and resource requirements are determined for various technology mixes chosen to represent the operation of all industrial boilers in two time periods, and to reflect an emphasis on one or another technology. Details of this methodology are presented in Appendix B.

The primary sources of data and information used in this study are the Environmental Assessment (EA) contractors and other EPA contractors. The primary contact, reports by the primary contractor, and secondary sources are also given in Appendix B for each of the technologies, as well as the details of the characterization for each of the individual technologies.

The comparison of technology mixes for using coal in industrial boilers is based on the aggregate discharges and resource requirements that would be expected from the trajectories comprising each mix. Industrial steam requirements are postulated to be satisfied by a variety of mixes of the eleven trajectories tabulated in Appendix B. All mixes, except the first one below, apply to the year 2000 and are based on the 6 Q level of demand discussed at the beginning of this chapter. The technology mixes are as follows:

Industrial Boilers in 1980: This mix assumes the coal technologies and levels of their application expected to be in use in 1980. Steam production amounts to 1.2 Q per year (requiring approximately 1.5 Q per year of coal). This mix is used for baseline purposes in some of the comparisons.

Industrial Boilers in 2000: This is the "reference mix" for the year 2000 because the level of application of each technology is that level assumed to be achievable according to market penetration estimates provided by the sources of the study, the Environmental Assessment contractors. In this and the subsequent technology mixes, the steam production is taken to be 4.8 Q per year. The coal required, nominally 6 Q per year, varies slightly with each technology mix because of overall efficiency differences.*

Clean, All Eastern Coal in 2000: All Eastern coal, except for that used in low-Btu gasification, is cleaned physically. Other assignments are the same as the reference mix above. This mix is also called the "clean coal mix" in the text.

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*Comparison for a different level of coal use can most simply be obtained by multiplying the values of discharges or resources by the factor $\frac{L}{6}$. This procedure, however, assumes that the mix of technologies remains the same.

TABLE 19. TECHNOLOGY MIXES AND THEIR ASSOCIATED TRAJECTORIES AND STEAM ASSIGNMENTS (Q/yr OF STEAM PRODUCED)

Trajectory/technology mix	Industrial boilers in 1980	Industrial boilers in 2000	Clean, all-Eastern coal in 2000	High level of scrubbing in 2000	High level of low-Btu gas in 2000	High level of FBC in 2000	Uncontrolled in 2000
Eastern Coal							
Conventional combustion	0.48	1.12	0	0	0	0	1.92
Conventional combustion/cleaned coal	0.35	1.12	2.24	1.12	1.12	1.12	1.40
Conventional combustion/FGD	0.07	0.64	0	1.76	0.64	0.64	0.28
Conventional combustion/FGD/cleaned coal	0	0	0.64	0	0	0	0
Fluidized-bed combustion	0	0.32	0	0.32	0.32	1.44	0
FBC/cleaned coal	0	0	0.32	0	0	0	0
Low-Btu gasification of coal	0	0.16	0.16	0.16	1.28	0.16	0
Western Coal							
Conventional combustion	0.30	0.96	0.96	0	0	0	1.20
Conventional combustion/FGD	0	0.16	0.16	1.12	0.16	0.16	0
Fluidized-bed combustion	0	0.16	0.16	0.16	0.16	1.12	0
Low-Btu gasification of coal	0	0.16	0.16	0.16	1.12	0.16	0
Total	1.20	4.80	4.80	4.80	4.80	4.80	4.80

High-Level FGD in 2000:	All coal from conventional combustion of uncleaned coal is shifted to FGD. Other assignments are the same as the reference mix above. This mix is also called the "scrubbing mix" or "FGD emphasis mix" in the text.
High Level of Low-Btu Gasification in 2000:	All conventional combustion of unclean coal is replaced by low-Btu gasification. Other assignments are the same as the reference mix above. This is also called the "low-Btu gas mix" in the text.
High Level of FBC in 2000:	All combustion of uncleaned coal is replaced by FBC. Other assignments are the same as the reference mix above. This is also called the "FBC emphasis mix" in the text.
Uncontrolled Mix in 2000:	Coal technologies satisfy the year 2000 steam demand of 4.8 Q in the same ratio as the mix of "Industrial Boilers in 1980." This mix is only used in the following chapter on air quality to indicate the potential pollution that would result from using uncontrolled technologies.

Table 19 details the trajectories that comprise each technology mix and their associated steam assignments.

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CHAPTER 7

PROFILES OF PRESENT AND FUTURE EMISSIONS FROM INDUSTRIAL BOILERS

The analysis in this chapter compares coal technologies with respect to air emissions. It also addresses the regional distribution of emissions from industrial boilers and assesses future national levels and the possible regional increases in emissions that would accompany a major shift to coal use in industry.

Only "major sources" as defined in the Clean Air Act and regulations proposed by the EPA pursuant to the Act are considered here (see further Chapter 6). Thus, emissions from "area" sources are omitted.* The analysis emphasizes the criteria air pollutants: total suspended particulates (TSP), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). These pollutants were chosen based on: 1) the availability of adequate, recent emission inventories; 2) the prominent role these pollutants play in regulations of the CAA, including Sec. 107 (attainment, unclassified, and non-attainment designations for the NAAQS) and Part C (PSD); and 3) the relatively large contribution that present industrial boiler fuel combustion makes to the total national emissions of these pollutants from all point sources. Table 20 displays the summary inventory for the 1980 national emissions file, as maintained by the EPA (1). Note that only TSP, SO_2, and NO_x emissions from combustion in industrial boilers exceed 10 percent of the total emissions of these criteria pollutants. Also, for the major fuels included in this analysis--coal (anthracite, bituminous, and lignite), oil (residual and distillate), and natural gas--only TSP, SO_2, and NO_x emissions exceed 30 percent of the total industrial boiler emissions.

Before discussing the results of the analysis, we should consider what effects the above analytical restrictions (sources, pollutants, and fuels) have on the conclusions. First, by considering only major sources, we have excluded over 450,000 industrial boilers from the analysis. These smaller boilers are primarily fired with oil or natural gas. Also, as discussed in Chapters 4 and 10, load factors tend to be less for these smaller boilers,

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*Emissions from "area" sources are calculated by applying emission factors to observations of fuel usage for other source categories. Since small industrial boilers are included in these other categories, are subject to a greater likelihood of error in emission estimates, and are excluded from present regulations of the CAA, they have been excluded from the present analysis. Such sources can, however, be significant contributors to emissions in certain areas.

TABLE 20. NATIONAL INDUSTRIAL BOILER FUEL EMISSIONS COMPARED TO TOTAL EMISSIONS[a]

Category	Total suspended particulates (TSP)	Sulfur oxides (SO_x)	Nitrogen oxides (NO_x)	Hydrocarbons (HC)	Carbon monoxide (CO)
Industrial boilers (10^6 tons)	0.9	3.2	2.3	0.1	0.2
Percent by fuel[b]					
Coal	63	57	26	15	11
Oil	10	35	23	19	16
Natural gas	3	2	32	14	26
Industrial boilers as percent of total point sources	12	12	21	2	3
TOTAL (10^6 tons)					
Point sources	8.1	27.8	10.8	5.5	8.9
Area sources	45.5	2.4	10.6	31.1	107.9
Grand total	53.6	30.2	21.4	36.6	116.7

[a] Figures as of February 8, 1980 from reference (1).

[b] Percentages do not add to 100 because of the contribution from "other" fuels.

and capital and annual costs in these smaller size ranges tend to be lower for oil- and natural gas-fired boilers. Thus, coal is not an attractive fuel for boilers in the smaller than 100,000 lb of steam per hour range. In any case, with this population of smaller boilers excluded, the future emissions estimates presented here will underestimate potential air pollution problems.

A second distortion is that limiting the analysis to TSP, SO_2, and NO_x emissions allows the emission problems from hydrocarbons (HC) and carbon monoxide (CO) to be ignored. This limitation has particular importance for new or modified large boilers located in urban areas, because most of the urban areas in the U.S. are presently in non-attainment for HC and CO. Approximately one-fifth of all large industrial boilers are now located in these urban areas. As a result, the problems of obtaining emission reductions in non-attainment areas under "offset" provisions of the CAA are also understated (discussed in Chapter 8).

Third, not all industrial boiler fuels are discussed in the analysis. This limitation has importance primarily on a regional basis. For example, wood-firing in industrial boilers is very important in the Southeast and Pacific Northwest regions, primarily in the pulp and paper industries. TSP emissions from wood-fired boilers are quite significant. Also, firing of by-product gases, such as bagasse, is significant in the Gulf Coast region.

In short, this analysis, while representative of the types of air quality problems to be expected under conditions of increased coal use in industrial boilers, does not capture the full magnitude of these problems.

EMISSIONS FROM INDUSTRIAL BOILERS

Historical Trends

As discussed in Chapter 2, the past few decades have witnessed a number of trends in industrial fuel use. First, the trend was away from coal to oil. Then, toward the late 1960s, natural gas became the predominant fuel. Within the past few years, oil has experienced a slight resurgence, concomitant with increased conservation of energy. These trends are depicted in Figure 22 in terms of TSP, SO_2, and NO_x emissions from industrial fuel combustion in the period 1940 through 1977 (2, 3).

Note the long-term decrease in TSP and SO_2. This decrease may be attributed to the declining use of coal (which disproportionately contributes to TSP and SO_2 levels), increased use of low sulfur oil, increased use of natural gas, and increased application of particulate (TSP) control. Also note the relative peak in NO_x emissions around 1970, which approximately corresponds to the peak in natural gas use. All pollutants show a leveling off or slight increase in national levels over the past few years, perhaps reflecting the decreased use of natural gas.

Table 21 presents the overall national trends in industrial boiler emissions over the past six years. The period 1972 through 1978, for which ade-

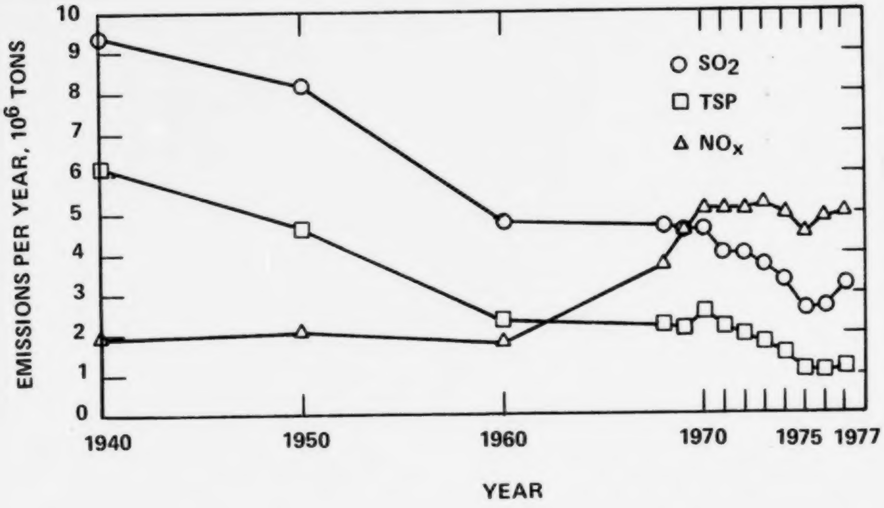

Figure 22. Industrial boiler emissions, 1940 through 1977 (2, 3).

TABLE 21. PERCENT CHANGE IN NATIONAL INDUSTRIAL BOILER EMISSIONS 1972-1978

	TSP	SO_2	NO_x
Coal	-52	-30	-35
Oil	+106	+66	+57
Natural gas	-16	+30	+116
Natural gas + oil	+77	+64	+91
Natural gas + oil + coal	-41	-6	+21
TOTAL (all fuels, including wood, etc.)	-40	0	-51

quate emission inventories are available, was chosen in order to compare pre-1973 oil embargo figures with those for the present. Coal emissions have dropped from a third to a half in six years. The importance of coal emissions is indicated by the fact that while natural gas and oil emissions increased, their increase was more than outweighed by declining coal use. The sharp drop in NO_x emissions in the total category is due to the phasing out of a few major primary metal facilities (particularly in the Great Lakes region), which burned process gas.

Current Emission Levels

A Source Category Perspective--

Emissions from industrial boilers in 1978, in millions of tons per year, are indicated in Table 20. To place these amounts in perspective, Figure 23 compares these emission levels with emissions from other major source categories: transportation; electric utilities; residential, commercial, and institutional; and non-boiler industrial processes. The emissions data presented are provided from unpublished, current files in the National Emissions Data System (NEDS) maintained by the Office of Air Quality, Planning, and Standards (OAQPS) of the EPA (4).

Industrial boilers are a major source category for the three pollutants under consideration, as shown in Figure 23. For each pollutant, industrial boilers are the third highest emitters in all source categories. Industry sources are second only to the electric utilities in terms of the total national burden of TSP, SO_2, and NO_x emissions. The largest NO_x source category is transportation. SO_2 burdens from electric utilities overwhelm all other categories, because 60 percent of baseload capacity is coal-fired and much relatively high sulfur residual oil is used in peaking units. Emissions of TSP are greatest from industrial process sources.

The importance of emissions from industrial boilers, however, cannot be understood simply on the basis of aggregate, national loadings. First, there are regional differences in emissions; these are the topic of the next section. Second, the locations of industrial boilers, and hence, the risks their emissions pose to nearby residents, must also be evaluated. As will be seen in Chapter 8, two-thirds of the emissions from large industrial boilers are released in municipal locations. Only transportation and residential and commercial sources occur so close to population centers.

A Regional Perspective--

Industrial capacities, and hence boiler emissions, are not uniformly distributed nationwide. Ten states, for example, contain close to 60 percent of all industrial boiler capacity (5). Using the CTA regions defined in Chapter 1, Figure 24 outlines the major 1978 emission patterns arising from all fuels burned in industrial boilers.

The region with the greatest industrial boiler emissions, by far, is the Great Lakes, with Appalachia and the Gulf Coast regions next. The westernmost regions--the Rocky Mountain, Pacific Southwest, and Pacific Northwest--show the fewest emissions, reflecting their overall lesser industrial development.

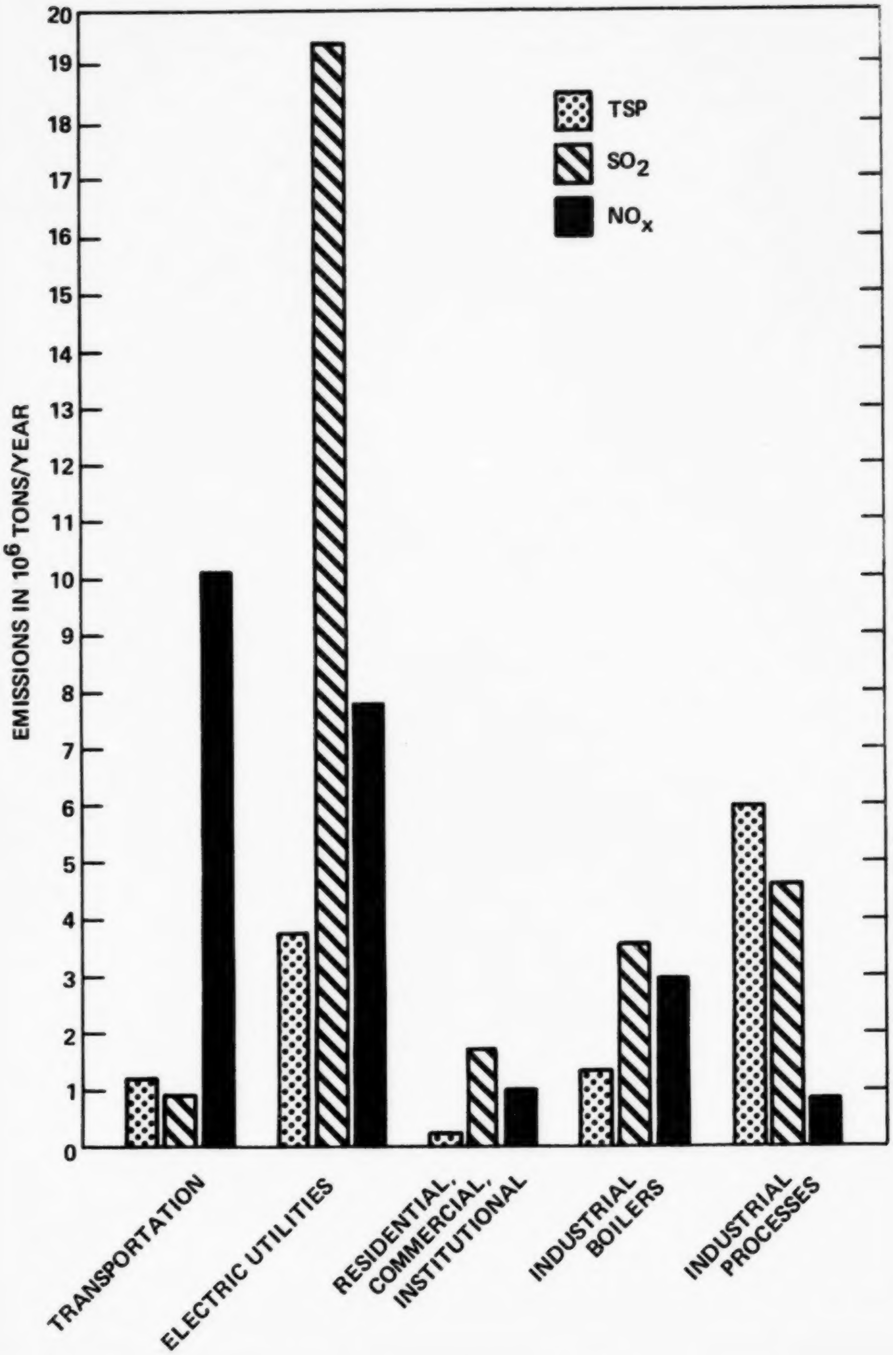

Figure 23. Emissions from major categories, 1978.

New England regional emissions are also fairly low; the remaining regions are intermediate to high.

The differences between regions are more pronounced when the contribution of emissions from firing each of the major fuels is considered. New England, for example, relies mostly on oil as a primary fuel; over three-quarters of that region's emissions come from oil. In fact, industrial emissions from oil firing in New England rival those from much larger industrial regions, including the Upper Atlantic, Great Lakes, and Southeast, while exceeding those in the very industrialized Gulf Coast states. But this is the case because oil is such a dominant source of fuel in New England; total emissions there are very much lower than for these other regions.

The three regions that lead in coal boiler emissions are, in order, the Great Lakes, Appalachia, and Great Plains; those are the regions closest to the traditional coal fields. Some regions, including New England, the Pacific Southwest, and the Pacific Northwest, have relatively insignificant emissions from coal firing. In these instances, distance from coal fields appears to be a factor.

By far the region in which natural gas emissions are highest is the Gulf Coast. The region with next highest natural gas use is the Great Lakes, followed at a distance by Great Plains, Appalachia, and the Pacific Southwest. Note that in all of these regions, NO_x emissions from natural gas are high, and TSP and SO_2 are low. One major impact of increased coal use in these regions would be greatly magnified SO_2 and TSP burdens.

Regions with high TSP emissions in the "other" category, but with dissimilar percentages for SO_2 emissions, are those in which a fair degree of wood and wood wastes are burned in industrial boilers. Regional examples include the Pacific Northwest, New England, and the Southeast. As shown in Chapter 5, these regions contain extensive pulp and paper industries. Regions with large shares of SO_2 and NO_x emissions in the "other" category have many boilers burning process gas or bagasse, typically in the petrochemical or food processing industries. The Gulf Coast region is a good example.

Not shown in Figure 24 is the relative importance of emissions from industrial boilers compared with total emissions from point sources. In the Pacific Northwest, NO_x emissions from industrial boilers are over half of the total NO_x emissions. This high percentage is atypical; it may be attributed, in part, to the fact that other major source categories in the region are relatively "clean" (for example, a prevalent "fuel" source in the region's electricity supplies is hydroelectric power). The industrial boiler/total point source relationship is close to the national average in New England. Other regions, such as the Rocky Mountain and Pacific Southwest, are lower than average, because industrial capacity is low. The largest industrial regions--the Great Lakes, Gulf Coast, Southeast, and Appalachia--indicate percentage shares slightly larger than the national average of industrial boiler to point source emissions.

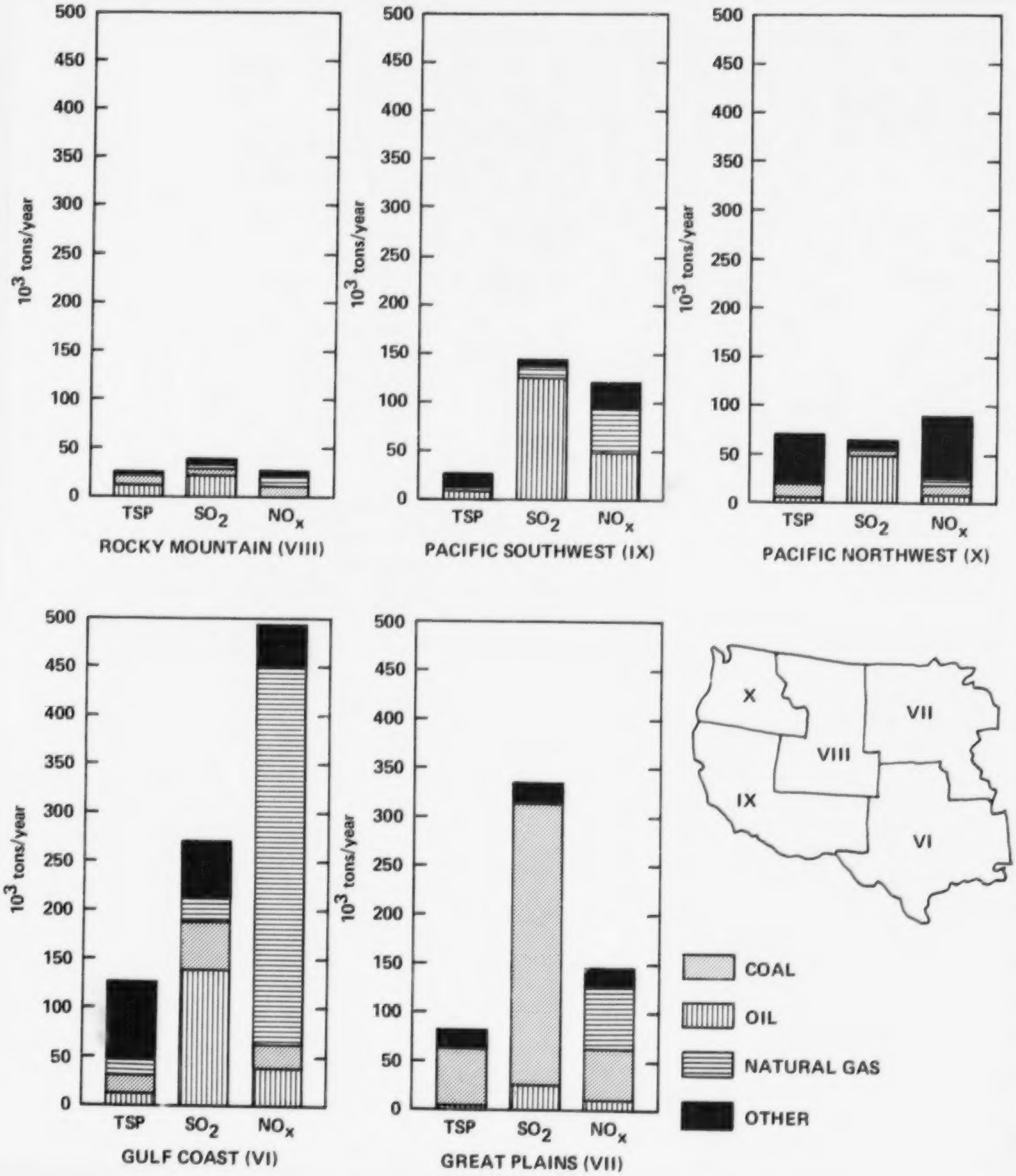

Figure 24. 1978 regional industrial boiler emissions, by fuel type.

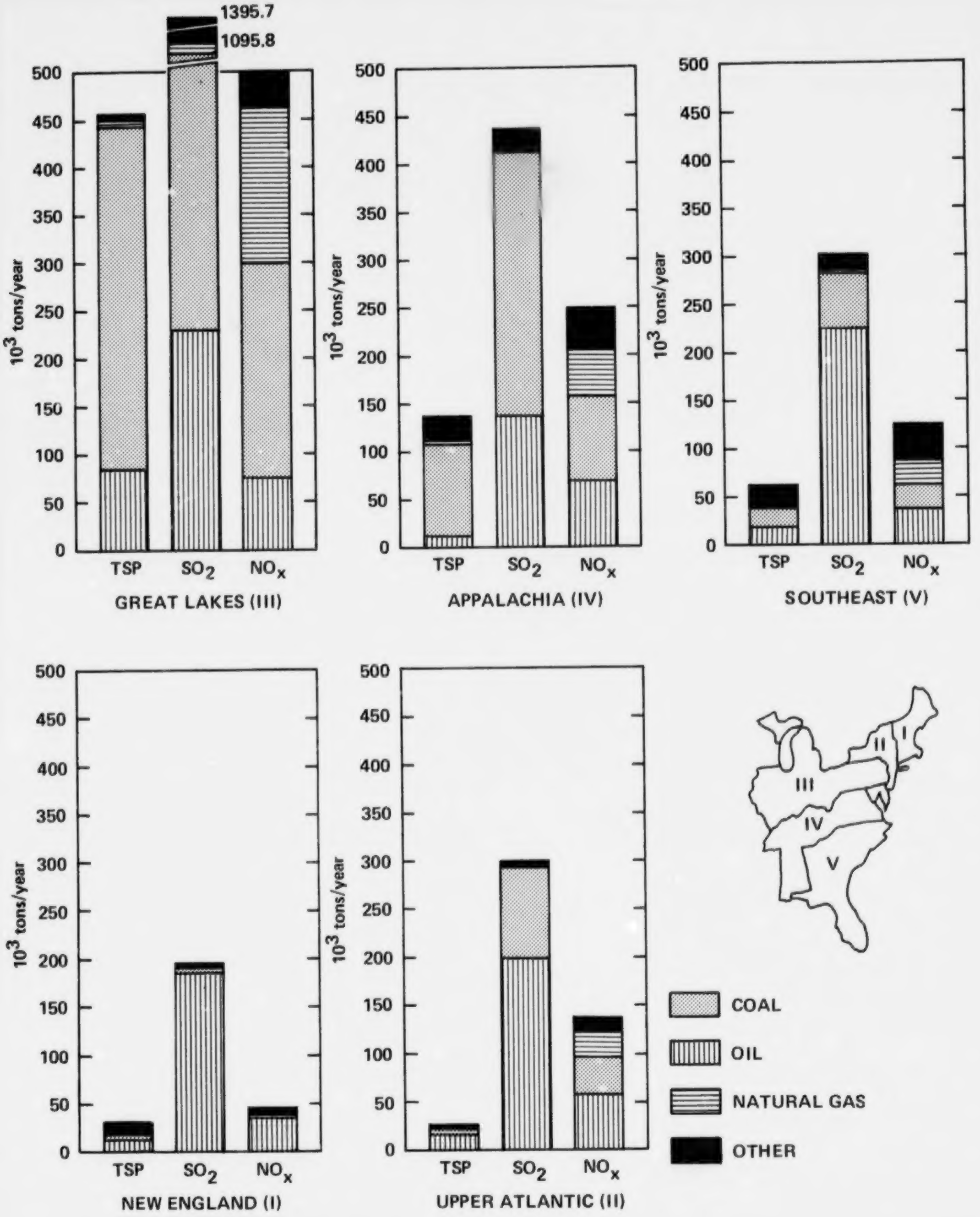

Figure 24. (continued)

COMBUSTION TECHNOLOGIES AND THEIR EMISSIONS

This section presents comparisons of air emissions from the seven coal combustion technologies described in Appendix B. The direct comparisons are based on delivering the same amount of useful steam, and take into account primary efficiency differences in the entire "trajectory" of mining the coal to producing the steam. The performance levels of these coal technologies are then compared with "typical" oil- and natural-gas-fired industrial boilers in the same size range. The comparisons offer an appreciation of the air quality challenges to be faced if coal is to be emphasized for use in industrial boilers.

Briefly, the seven coal technologies are: conventional combustion (CC); conventional combustion of physically cleaned coal (CC-PCC); conventional combustion with flue-gas desulfurization (CC-FGD); conventional combustion of physically cleaned coal with FGD (CC-PCC-FGD); fluidized-bed combustion (FBC); fluidized-bed combustion of physically cleaned coal (FBC-PCC); and low-Btu gasification with gas burned in the boiler. Operating parameters, efficiencies, coals utilized, and boiler size are the same as outlined in Chapter 6 and Appendix B, to which the reader is referred for a complete description of the methodology employed.

A Comparison of Air Emissions

Results of the direct comparison of technologies using Eastern coal are shown graphically in Figure 25. Total quantities of individual air emissions produced by all operations from mining through boiler operation are shown in pounds per million Btu of steam produced. As a supplement to this display, the same results for Eastern coal, and the corresponding results for Western coal, are depicted in Table 22; however, the results in Table 22 are given as a percent change from the results for conventional combustion of Eastern or Western coal, as appropriate. In this format, negative values in Table 22 show reduced emissions relative to conventional combustion, while positive values show increased emissions. Direct comparison of the technologies with respect to their air emissions is seen better in Figure 25; Table 22 provides the better picture of the overall performance of a given technology.

The technologies compared in this analysis have varying effectiveness in reducing emissions of SO_2. Cleaned coal burned in a conventional boiler produces 38 percent less SO_2 than uncleaned coal, while scrubbing and fluidized-bed combustion reduce SO_2 about 90 percent over conventional combustion. The use of cleaned coal with FGD and FBC does not further reduce SO_2 because it is assumed that SO_2 reduction must meet a given regulation; the required reduction by FGD or FBC is therefore less if cleaned coal is used. In fact, the total SO_2 for the entire trajectory is slightly higher for cleaned coal plus FGD than for FBC alone, since some SO_2 is discharged from the thermal dryer at the coal cleaning plant. The advantage of using cleaned coal with FGD and FBC lies in the fact that smaller quantities of ash and FGD sludge or FBC spent bed are produced at the boiler site. (This topic is more thoroughly discussed in Chapter 9.) Low-Btu gasification produces the smallest amount of SO_2, about 94 percent less than conventional combustion,

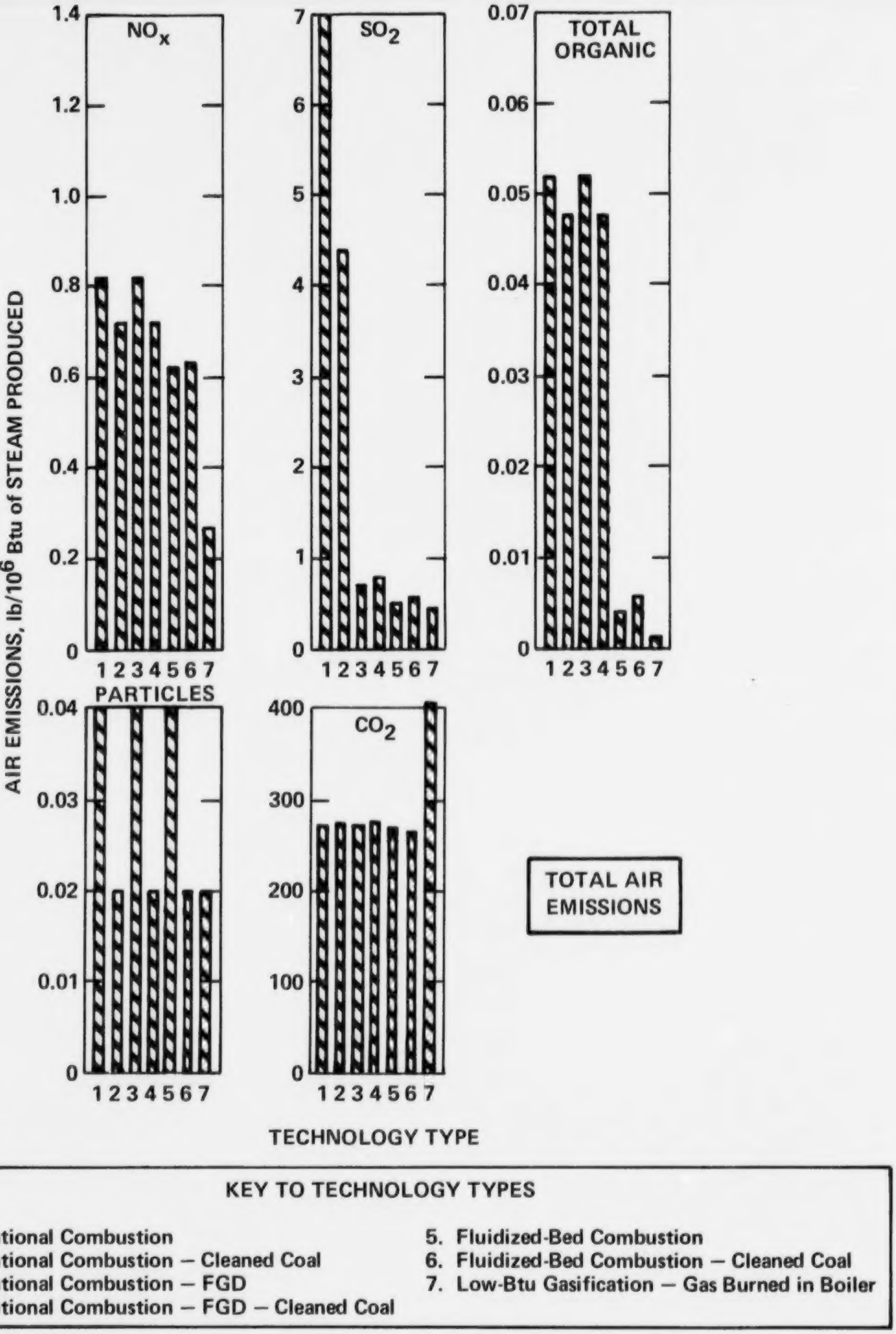

Figure 25. Air emissions by technology.

TABLE 22. AIR EMISSIONS FROM INDUSTRIAL BOILER TECHNOLOGIES AS PERCENTAGE DIFFERENCE FROM CONVENTIONAL COMBUSTION

Technology	Particulates (TSP)	SO_2	NO_x	HC	CO_2
		Eastern Coal			
Conventional combustion (CC) with cleaned coal	-50	-38	-12	-8	+1
CC with flue-gas desulfurization (FGD)	0	-90	0	0	0
CC with FGD with cleaned coal	-50	-89	-12	-8	+1
Fluidized bed combustion (FBC)	0	-93	-24	-92	-1
FBC with cleaned coal	-50	-92	-23	-89	-3
Low-Btu gasification of coal	-50	-94	-67	-98	+48
		Western Coal			
CC with FGD	0	-90	0	0	0
FBC	+18	-67	-39	-94	-5
Low-Btu gasification of coal	+27	-94	-75	-98	+39

among the technologies investigated.

Fluidized-bed combustion provides somewhat better control of NO_x and much better control of hydrocarbon emissions than does conventional combustion. Both emission values for FBC are based on measured data (obtained from EPA's Environmental Assessment [EA] program, as outlined in Appendix B).

Except for a reduction in SO_2, flue-gas desulfurization shows little improvement in the other emission categories over uncontrolled combustion. However, no hydrocarbon emission data were available for FGD, and the EA source consulted indicated that no NO_x reduction is achieved. Therefore, emission factors for NO_x and total organic (hydrocarbon) emissions published by EPA for conventional combustion were used for FGD. Since Western coal has a lower Btu content per pound than Eastern coal, the resulting NO_x factor for Western coal on a Btu basis is higher than for Eastern coal.

The figures for total suspended particulates (TSP) reflect 99 percent removal efficiency from the boiler flue gases. This assumption is optimistic, since the current average removal efficiency for boilers with TSP control is about 84 percent. Note, however, that physical coal cleaning and low-Btu gasification do greatly reduce TSP emissions. Differences among the other technologies are slight.

Low-Btu gasification provides the greatest reductions in air emissions, except for CO_2. Since CO_2 generation is related to the quantity of coal consumed, the lower efficiency of the low-Btu gasification trajectory results in a significant increase in CO_2 released. The result shown for total organic emissions is subject to error for this technology. Unquantified emissions of hydrocarbons occur during the gasification process, and these are not included in the results. The exceptionally good performance of low-Btu gasification with respect to air emissions must be considered in the light of poor performance with respect to solid waste production and resource requirements (Chapter 9) and, comparatively, very high costs (Chapter 10).

All characterizations presented herein are based on normal operation, 100 percent availability of control if utilized, and pollutant removal efficiencies at rated values. Variations resulting from startup and shutdown, wide load swings, coal feed variations, and other abnormal operations have not been considered. These factors, as well as the assumed TSP removal efficiency, combine to produce an overly optimistic picture with respect to air emissions from coal-fired boilers.

Coal-Use Technologies in Perspective: A Comparison to Oil and Natural Gas

Chapter 5 documents the very large role natural gas and oil play in fueling industrial boilers. As shown in Chapter 3, the Fuel Use Act mandates, subject to certain exemptions, that new industrial boilers must use alternative fuels. Presumably, coal is the leading alternative. In this section, emissions of TSP, SO_2, and NO_x from uncontrolled oil- and natural-gas-fired boilers are compared to those from the candidate coal technologies under investigation. The comparison considers only the emissions from the boilers, not the entire fuel cycle from mining to end use. The narrower focus of boiler emissions allows comparisons of the direct trade-offs the various fuels and technologies present.

Consistent with the other analyses in this report, boilers delivering 100,000 lb of steam per hour are the basis for comparison. The boilers operate at a 45 percent load factor (determined as the number of hours each year that the boiler operates times its average percent capacity). The same "typical" Eastern and Western coals previously mentioned are assumed for the coal technologies. Average efficiency for both the natural-gas- and oil-fired boilers is 84 percent. Residual oil is #5, 0.5 percent sulfur content. The distillate oil has 0.2 percent sulfur content.

Figure 26 displays the emissions loadings calculated for the various fuels and technologies, expressed in tons per year. Each bar chart represents the emissions from one boiler. For all of the coal technologies, except physical coal cleaning, emission profiles for burning both Eastern and Western coals are shown. Note, however, that results for fluidized-bed combustion (FBC) are the same for both coal types.

Natural gas produces the fewest TSP emissions, though low-Btu gasification and physical cleaning of coal have as low, or lower, emissions than does distillate oil. In general, Western coal produces fewer TSP emissions than does Eastern coal. Most apparent, however, are the high TSP emissions from firing residual oil: at least two times more TSP than with the next worse case. Recall, though, that very optimistic TSP control is assumed for all of the coal boilers. Should removal efficiencies be 98 percent rather than 99 percent, all of the cases shown for coal would greatly exceed the TSP emissions for distillate oil, and about half would equal those for residual oil. And should removal efficiencies be factored in at the present average, 84 percent, the bars for the coal technologies would dwarf those for residual oil.

The higher sulfur content of coal, as opposed to oil or natural gas, can be seen in the SO_2 emissions for conventional combustion of coal in Figure 26. Most significantly, natural gas produces essentially no SO_2. However, with Western coal (0.7 percent sulfur content), the SO_2 emissions from low-Btu gasification and flue-gas desulfurization are also quite low. All of the coal technologies firing Eastern coal emit more SO_2 than do technologies firing distillate oil. When compared with residual oil, low-Btu gasification and FBC are the only two coal technologies exhibiting superior performance, though FGD is also not significantly greater. Of prime importance are the very much higher SO_2 emission figures for conventional (uncontrolled for SO_2) combustion and physical coal cleaning. What is most disturbing about these high figures is the implication that, if coal use is to be emphasized in industrial boilers, and if markedly increased SO_2 emissions will also not be politically acceptable, then only the most advanced and expensive (see Chapter 10) coal technologies could be employed. In certain regions, as well, where the capacity of natural-gas-fired boilers is presently great, even emphasizing these advanced technologies in the future may lead to significant increases in SO_2 levels.

With the exception of low-Btu gasification, a similar, but more pronounced, profile emerges for NO_x emissions from the coal technologies. Partially, the visibly worse performance for the coal technologies with respect to NO_x results from the fact that no NO_x controlling technologies were included in the sampling of coal technologies under investigation. Yet, as in the case for the other two pollutants, when uncontrolled, coal is dirtier than natural gas or oil.

From an air quality perspective, natural gas, closely followed by distillate oil, is the most ideal fuel of those considered for firing in industrial boilers. The only coal combustion technology that can rival their performance is low-Btu gasification.

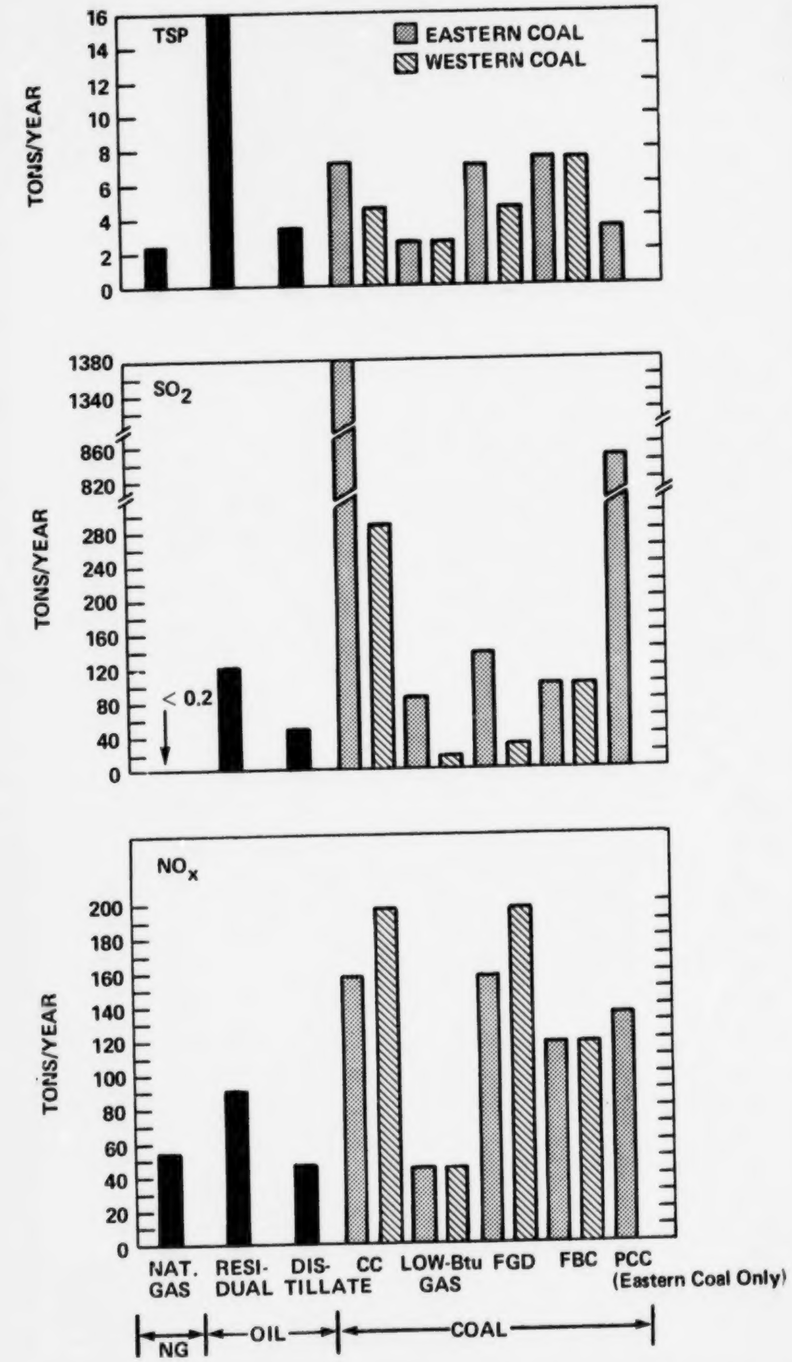

Figure 26. A comparison of yearly emissions from single natural gas-, oil-, and coal-fired boilers, 10^5 lb steam/hr, 45% load factor.

YEAR 2000 EMISSIONS: A COMPARISON OF TECHNOLOGIES AND REGIONS

Assigning Future Capacity

Chapter 6 outlines a 6 Q demand for primary energy in large coal-fired industrial boilers in the year 2000. What this demand would imply about regional equity in emissions burdens and the choice of coal technologies is the subject of this section. Incorporating different "mixes" of coal-fired industrial boilers into the same assignments outlined in Chapter 6 can demonstrate the potential that the various coal technologies have in altering or improving overall air quality for each region.

The same technology mixes specified in Chapter 6 are used for the comparisons presented here. Emissions from oil- and natural-gas-firing are included in some of the comparisons. In these cases, future oil- and natural-gas-boiler emissions are assumed to increase or decrease in the year 2000 as a function of the simple ratio of the year 2000 primary energy demand to 1978 primary energy demand for each fuel.

National Emissions

Two types of comparisons are drawn for the year 2000 national emissions. The first compares the technology mixes described in Appendix B on the basis of the entire trajectory from mining the coal to producing the steam. Such a comparison accounts for all air emissions in all steps of the fuel cycle, thus providing for the most complete index by which to compare the technology mixes. The second comparison considers emissions from the boilers only. Since current methods for counting emissions (that is, the National Emissions Data System) focus at the level of the point source and not the entire trajectory, the use of boiler emissions alone enables future emissions to be compared on a common basis with present emissions. Therefore, the emissions burdens of the various coal technology mixes under consideration may be related to the present emissions burdens arising from the use of all major fuels.

The technologies employed and the levels of applications assumed in each of the coal technology mixes are listed in Table 19 of the previous chapter. Each mix compared delivers the same amount of useful steam. Recall that the "reference mix" represents the best judgment of the appropriate Environmental Assessment (EA) contractor for the year 2000 market penetration for each technology included. Furthermore, recall that the levels of coal cleaning, scrubbing (FGD), FBC, and low-Btu gasification emphasized in the other four technology mixes are not expected to be realized. They are postulated only to illustrate what consequences could be expected if high levels were achieved through accelerated research and development or through economic incentives, or both.

Comparison of the Coal Technology Mixes--

Table 23 presents the national air emissions for the entire fuel trajectory for each of the coal technology mixes under investigation. In the reference mix, SO_2 from coal will come to about 7.5 million tons per year, a

TABLE 23. YEAR 2000 TECHNOLOGY MIXES AND ASSOCIATED AIR EMISSIONS (10^6 TONS/YR)

	TSP	SO_2	NO_x	HC	CO_2
Reference mix	0.14	7.5	1.9	0.11	690
Scrubbing (FGD) emphasis mix	0.14	3.3	1.9	0.11	690
Physical coal cleaning emphasis mix	0.12	6.1	1.8	0.11	690
Low-Btu gasification emphasis mix	0.14	3.1	1.2	0.05	820
Fluidized-bed combustion emphasis mix	0.14	3.4	1.6	0.05	680

substantial increase over the other mixes. This amount represents almost 50 percent of present SO_2 emissions from the electric utility sector, by far the largest contributor to current U.S. SO_2 levels. The scrubbing, low-Btu gasification, and FBC emphasis mixes emit about half as much SO_2 as does the reference mix. Application of physical coal cleaning to all Eastern coal fired in industrial boilers in the year 2000 leads to a 20 percent reduction in SO_2 levels over the reference mix. These SO_2 emissions are likely to occur mostly in areas of the U.S. already suffering environmental insult from SO_2. Furthermore, such emissions would be discharged from short stacks and often from facilities located in urban areas. Hence, they would have adverse effects out of proportion to the total emitted. Discharges of other criteria air pollutants (NO_x, hydrocarbons, and particulates) will remain small fractions of nationwide totals, despite the large increase in industrial boiler operation. NO_x would increase by a factor of nearly four, but still would be less than two million tons per year, or less than 8 percent of all NO_x emissions in 1978 (4). NO_x emissions are relatively low for most of the technologies considered and, most importantly, are rather insensitive to the mix of technologies. Particulate emissions can be kept low because 99 percent collection is within the capability of available control equipment. However, if processes of the future are operated at the current average collection efficiency of only 84 percent, particulates from industrial boilers may be troublesome, especially in sensitive locations. Other air pollutants are insignificant compared with the quantities emitted nationwide. However, the composition of hydrocarbons emitted from industrial boilers is not documented, and highly offensive compounds such as polycyclic organics may be present in significant amounts if boiler use is increased as projected. Moreover, marked differences may exist in the types of hydrocarbons emitted from the different technologies.

On the basis of air emissions, then, the most significant difference between the mixes of technologies is in SO_2 emitted, as shown in Table 23. The following analysis reinforces this view.

Comparison of Present and Future Emissions--

Table 24 presents the percent change in emissions from the firing of oil, natural gas, and coal in industrial boilers between now and the year 2000 for the level of demand postulated. The table considers boiler emissions only and

TABLE 24. PERCENT CHANGE IN NATIONAL INDUSTRIAL BOILER EMISSION BETWEEN THE YEARS 1978 AND 2000

Mix	TSP[a] (% change)	TSP[b] (% change)	SO_2 (% change)	NO_x (% change)
Uncontrolled mix[c]				
Coal only	-93	+12	+248	+20
Coal, oil, and natural gas	-77	+27	+273	+74
Reference mix				
Coal only	-93	+18	+142	+12
Coal, oil, and natural gas	-77	+34	+167	+66
Clean coal mix				
Coal only	-94	-8	+93	+6
Coal, oil, and natural gas	-79	+8	+118	+60
Scrubbing mix				
Coal only	-92	+28	+6	+12
Coal, oil, and natural gas	-76	+44	+31	+66
Low-Btu gas mix				
Coal only	-96	-33	0	-30
Coal, oil, and natural gas	-80	-18	+25	+24
FBC mix				
Coal only	-91	+44	+8	-7
Coal, oil, and natural gas	-75	+60	+33	+47

[a] Uniform application of particulate control with removal efficiency of 0.99.

[b] Uniform application of particulate control with removal efficiency of 0.84.

[c] Expansion of the 1978 industrial mix of coal-fired boilers to the coal demand level specified for the other year 2000 mixes (6 Q primary energy demand; 4.8 Q of delivered steam).

applies the same technology mixes and other assumptions discussed previously. Two columns for TSP are given in the table. The one on the left indicates the potential for TSP reductions if particulate control is applied to all new boilers firing coal, at 99 percent removal efficiency. The right-hand column indicates 84 percent control on the same boilers. SO_2 and NO_x are also shown on the table. The "uncontrolled mix" simply represents the emissions in the year 2000 from a population of coal boilers consisting entirely of conventional combustion units.

For all of the mixes, except for the physical coal cleaning and low-Btu gas mixes for TSP and the low-Btu and FBC mixes for NO_x, the year 2000 emissions from the coal technologies alone are substantially higher than the total 1978 emissions for all fuels burned in industrial boilers. When the year 2000 emissions from oil and natural gas are added to those from coal, only the TSP level for the low-Btu gas mix shows a decline over the 1978 level. Again, however, the proviso must be entered that the projected TSP control levels are optimistic.

One of the more telling comparisons of the mixes is that for SO_2. The reference mix would produce substantial emission increases. There is no mix listed that can reduce year 2000 SO_2 emission levels to less than present emissions. Unless scrubbing, low-Btu gas, or FBC is very vigorously pursued, SO_2 emissions from industrial boilers will at least double. Even the fostering of low-Btu gasification could result in no net improvement, but great cost. Also, physical cleaning of Eastern coal alone has a relatively minor effect on SO_2 control. Thus, the high absolute levels of SO_2 (shown in the previous section), plus the perceptibly higher percentage increases, indicate that SO_2 will be the most troublesome air pollutant to be managed if coal use is greatly expanded.

The importance of changes in NO_x emissions is more difficult to judge. On the one hand, for the conditions postulated, overall NO_x emissions from boilers in the year 2000 will increase by at least one-quarter. On the other hand, the absolute increases are relatively minor compared with those of other sources. In all likelihood, NO_x problems may only have significance for particular locales. Indeed, such was the case for a brewery in the Los Angeles area where the owners desired to install two new boilers of a size comparable to the boilers investigated in this report (6). When brewery owners asked for a permanent exemption from the Fuel Use Act because of NO_x problems in the Los Angeles Basin, they were instructed to determine the feasibility of five alternate fuels: coal, low-Btu gas, refuse, solar, and petroleum coke. Coal, refuse, and coke violated the NO_x standards. Low-Btu gas and solar were too expensive. The brewery was thus granted, after a year-long delay, the first permanent exemption under the Fuel Use Act. The brewery will now burn distillate oil or natural gas in its new boilers.

Regional Emissions

Regional emissions presented in this section are the result of the regional fuel and coal assignments described in Chapter 6. The year 2000 regional emissions presented herein exclude emissions from the combustion of "other" fuels, notably TSP from wood and NO_x and SO_2 from process gas. The regions most likely to experience heavy emissions from these fuels in the future are likely to be the same regions that now burn large amounts of the other fuels. A previous section in this chapter identified such regions. Nevertheless, the profiles of future regional emissions offered here do take into account emissions from the use of the major fuels in industrial boilers (coal, oil, and natural gas) and do provide a relative indication of the burdens each region may experience if coal use is greatly expanded.

Results of Regional Emissions Assignments--

Figure 27 and Table 25 present the results of the regional assignments. Figure 27 offers bar graphs for each region showing the percent change in TSP, SO_2, and NO_x emissions between the years 1978 and 2000. Percent differences are calculated on the basis of the total annual emissions for the two years being compared. The percent change reflects the total increase or decrease in emissions from the combustion of coal (according to the various mixes of technologies), oil, and natural gas in industrial boilers. Table 25 provides absolute values for emissions from the use of coal in the year 2000, according to region. Also, recall that oil and natural gas emissions included in the bar charts in Figure 27 have been calculated by the simple ratio of year 2000 fuel use to year 1978 fuel use for each fuel, the result of which is then multiplied by the annual emissions for that fuel in 1978.

In comparing the technology mixes in Figure 27, it is instructive to use the "reference mix" as a baseline, since it does represent best current judgments concerning market penetration shares for the coal technologies being investigated. For the reference mix, increases are shown in all regions for TSP, NO_x, and SO_2 emissions in the year 2000, except for TSP in the Great Lakes and Appalachia regions, and SO_2 in the Great Plains region. These three are presently the largest coal-consuming regions. The improvement may be attributed to replacement of uncontrolled, existing capacity by new, controlled capacity. Increases in the Gulf Coast approach 1000 percent for SO_2 and TSP by the year 2000 for the reference mix. SO_2 levels are five times higher in the Pacific Southwest.

In those regions burning Western coal only, no physical coal cleaning is applied, and emission levels for the PCC mix are identical to the reference mix. For the regions burning Eastern coal, best exemplified by New England, the clean-coal emphasis mix demonstrates some improvement over the reference mix, especially in TSP levels. Improvement is less for NO_x and SO_2. For all ten regions for NO_x, nine of the ten regions for SO_2, and seven of the ten regions for TSP, however, improvements noted with the coal cleaning mix are still insufficient to result in a net improvement in air quality in the year 2000 over 1978 values.

The mix emphasizing scrubbing indicates SO_2 levels two to four times lower than the reference mix, depending on the region and its fuel use. NO_x levels remain unchanged from the reference mix. In the regions where Eastern coal is burned, slight increases in TSP emissions over the reference mix are indicated.

TABLE 25. YEAR 2000, REGIONAL COAL EMISSIONS (10^3 TONS/YR)

	Region	Reference mix			Scrubbing emphasis			Clean coal emphasis			Low-Btu gas emphasis			FBC emphasis		
		TSP	SO_2	NO_x	TSP	SO_2	NO_x	TSP	SO_2	NO_x	TSP	SO_2	NO_x	TSP	SO_2	NO_x
I	New England	26.3	252.7	45.7	29.3	118.9	45.7	18.2	195.4	42.0	17.1	113.2	33.6	30.0	114.7	41.5
II	Upper Atlantic	50.9	450.0	92.1	56.1	206.6	92.1	37.1	351.9	85.9	32.7	196.1	63.2	59.8	203.1	80.6
III	Great Lakes	198.3	1765.5	366.2	217.4	760.3	366.2	148.0	1321.4	343.2	127.0	720.6	242.9	236.5	755.4	314.9
IV	Appalachia	106.5	942.0	192.9	117.4	432.5	192.9	77.6	736.6	179.7	68.5	410.6	132.3	125.2	425.1	168.7
V	Southeast	139.1	1230.4	251.9	153.4	564.9	251.9	101.4	962.1	234.7	89.5	536.2	172.8	163.5	555.2	220.3
VI	Gulf Coast	499.3	2177.4	652.4	345.5	899.6	652.4	268.1	1777.6	626.6	203.2	844.0	370.6	411.6	959.1	520.4
VII	Great Plains	110.4	249.8	125.3	51.8	78.8	125.3	52.4	222.3	123.5	34.2	71.2	58.3	77.1	104.3	91.4
VIII	Rocky Mountain	32.0	42.0	33.8	14.3	7.1	33.8	32.0	42.0	33.8	8.5	5.5	13.8	20.5	16.1	23.4
IX	Pacific Southwest	89.5	117.5	94.5	40.1	20.0	94.5	89.5	117.5	94.5	23.7	15.3	38.7	57.5	45.1	65.5
X	Pacific Northwest	40.1	52.6	42.3	18.0	8.8	42.3	40.1	52.6	42.3	10.6	6.8	17.3	25.7	20.2	29.3
	TOTAL	1292.4	7279.8	1897.1	1049.3	3097.5	1897.1	864.4	5779.4	1806.2	615.0	2919.5	1143.5	1207.4	3198.3	1556.0

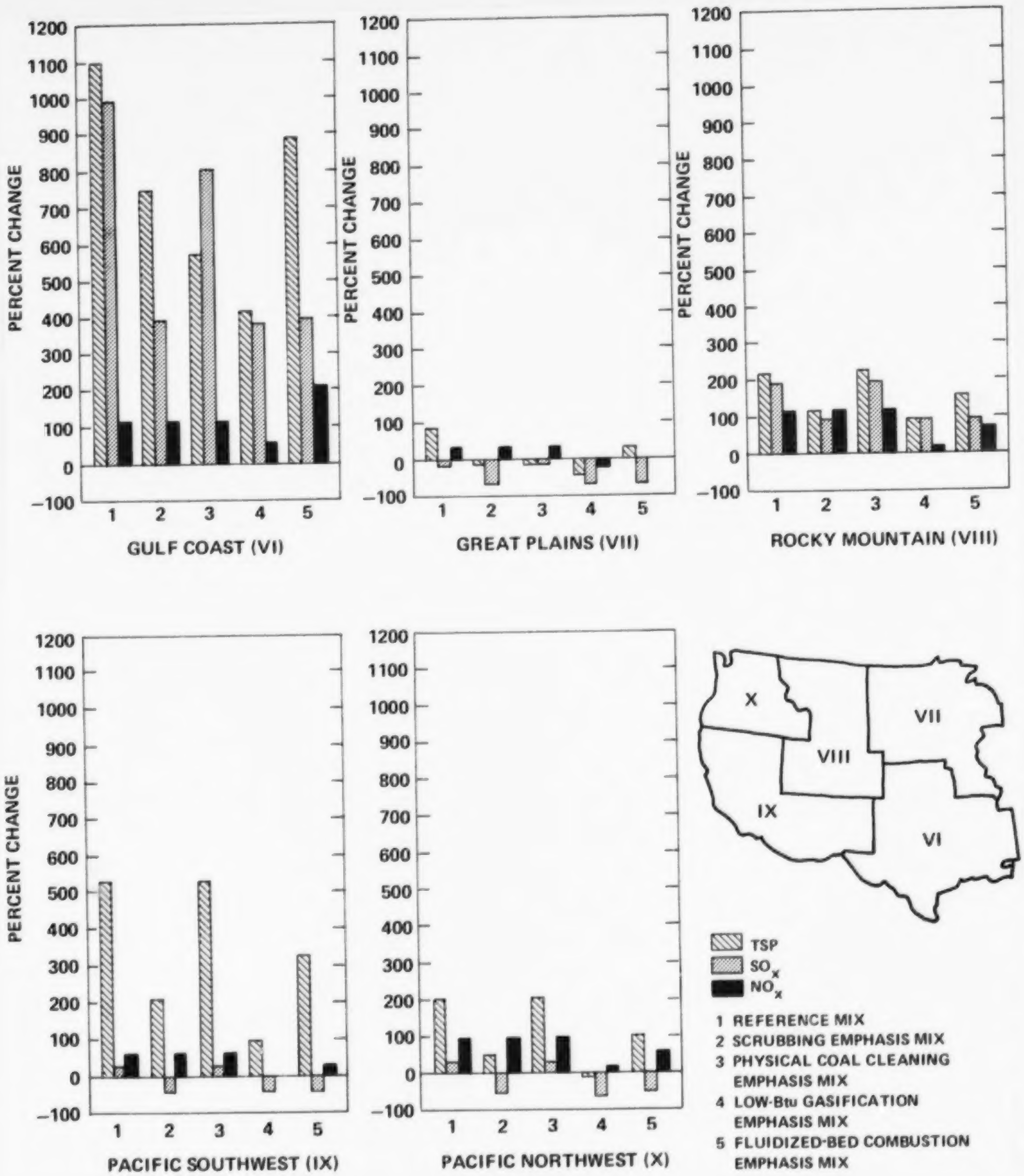

Figure 27. Percent change in regional industrial boiler emissions from 1978 to 2000, according to coal technology mix.

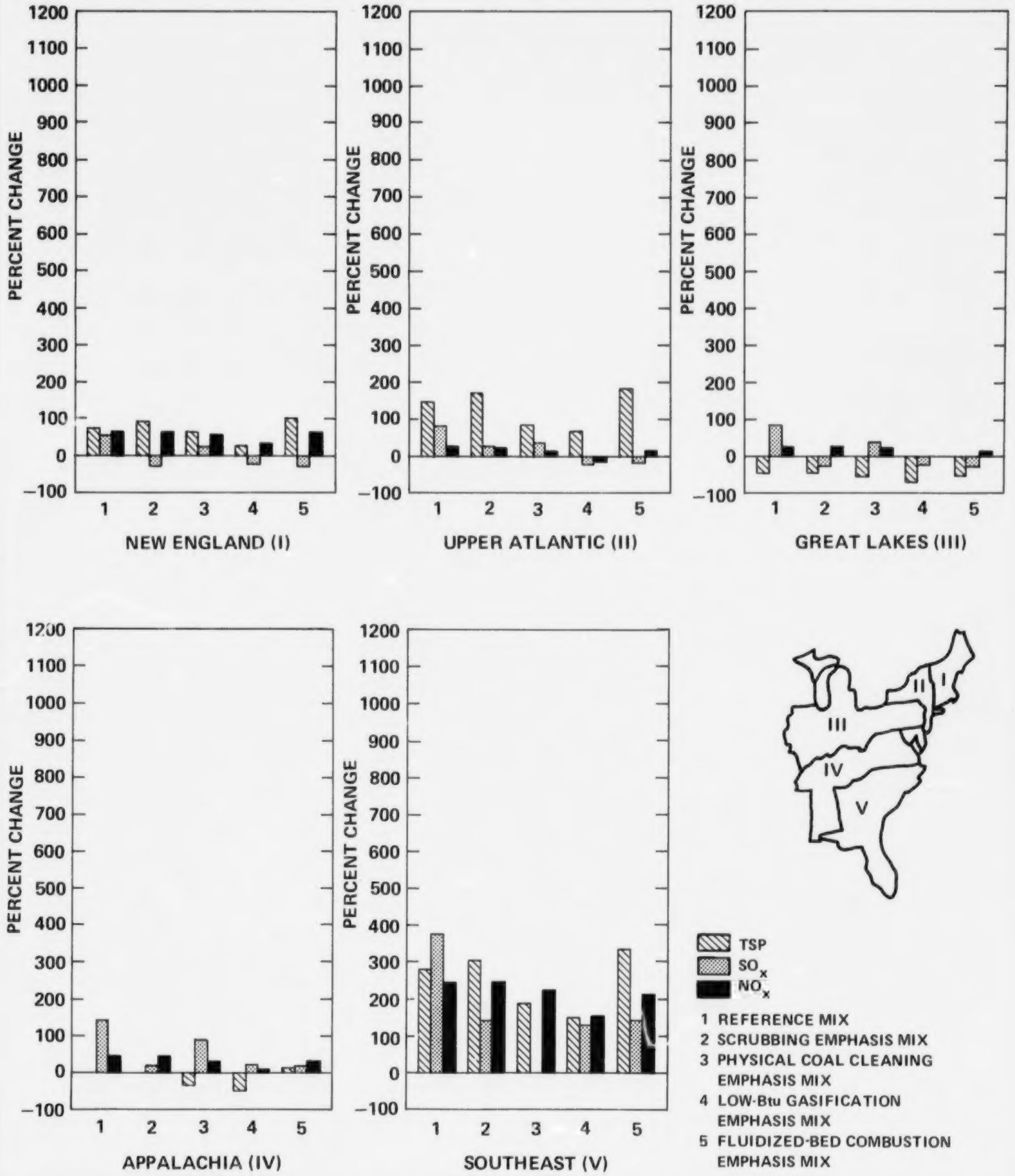

Figure 27. Percent change in regional industrial boiler emissions from 1978 to 2000, according to coal technology mix (concluded).

Levels of SO_2 and NO_x in the mix emphasizing fluidized-bed combustion are much improved over the reference mix. NO_x levels are slightly better than the scrubbing mix, with SO_2 emissions virtually equal. In all regions where the majority of coal burned is Eastern, however, the FBC mix shows the highest TSP levels. FBC may therefore be most appropriate in regional- and site-specific contexts where SO_2 and NO_x emissions are troublesome, but where particulates are not.

Not surprisingly, the mix emphasizing low-Btu gasification produces the fewest emissions in all categories and in all regions. What is surprising, though, is that even with the relatively high coal-use levels postulated, about half of the emission and regional categories indicate improvement over 1978 emission levels for the low-Btu gasification mix. Of particular importance are the substantial NO_x reductions for the low-Btu gas mix over the other mixes. Nonetheless, NO_x emissions generally increase across the board.

A Shift in Regional Burdens--

It is at the level of comparing regions, and not mixes of technologies, where the most telling conclusions may be drawn. The regional differences have more importance because, fundamentally, differences in present fuel-use patterns are more significant than the differences in the coal technologies being investigated. As intuition would suggest, regions in which the use of natural gas predominates are the regions that would have the greatest increase in emissions under conditions of increased coal use.

Figures 28 and 29 are an attempt to portray the shifting regional burdens from future increases in coal use, as well as the absolute levels of emissions these shifts represent. Both figures are based on the coal, oil, and natural gas emissions projected for the year 2000 reference mix. Figure 28 indicates the relative importance of each region's emissions from industrial boilers in the present and in the year 2000. Figure 29 maps the changes in industrial emissions from boilers, calculated on the basis of the average emissions per square mile for the entire U.S. in 1978. Of course, the latter measure will underestimate the regional problems, since neither industrial boilers nor their emissions are distributed uniformly in any given region.

The Gulf Coast would, by far, suffer the greatest impact from increased use of coal in industrial boilers, both in terms of absolute increases in pollutant levels and in percent change. Industrial capacity in the Gulf Coast is the largest of all the CTA regions, and existing capacity is overwhelmingly fueled by natural gas. Figure 28, for example, shows that over 35 percent of the total U.S. TSP and NO_x emissions, and over 25 percent of SO_2 emissions from combustion in industrial boilers in the year 2000 would occur in the Gulf Coast region. The relative importance of TSP emissions in the Pacific Southwest, another region that now relies heavily on natural gas, would also increase. In relative terms, regions where large amounts of coal are now burned, such as the Great Lakes and Great Plains, would decline in importance. Appalachia would remain fairly stable, and the Southeast would become relatively more important. The western U.S. would remain a relatively small contributor to national emissions from industrial boilers.

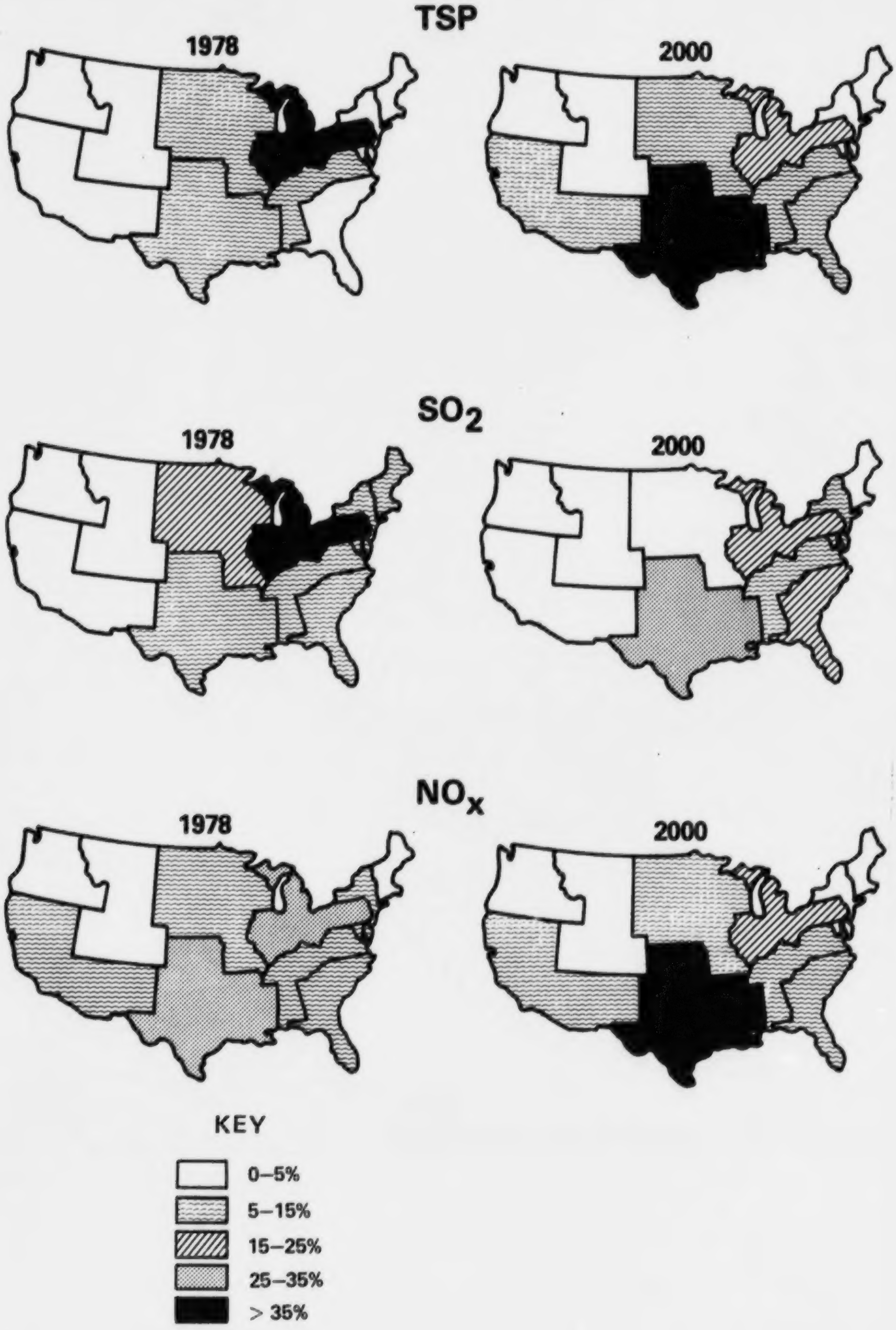
TSP
1978
2000
SO2
1978
2000
NOx
1978
2000
KEY
0–5%
5–15%
15–25%
25–35%
> 35%

Figure 28. Comparison of 1978 and 2000 percentage of regional burdens from industrial boiler emissions.

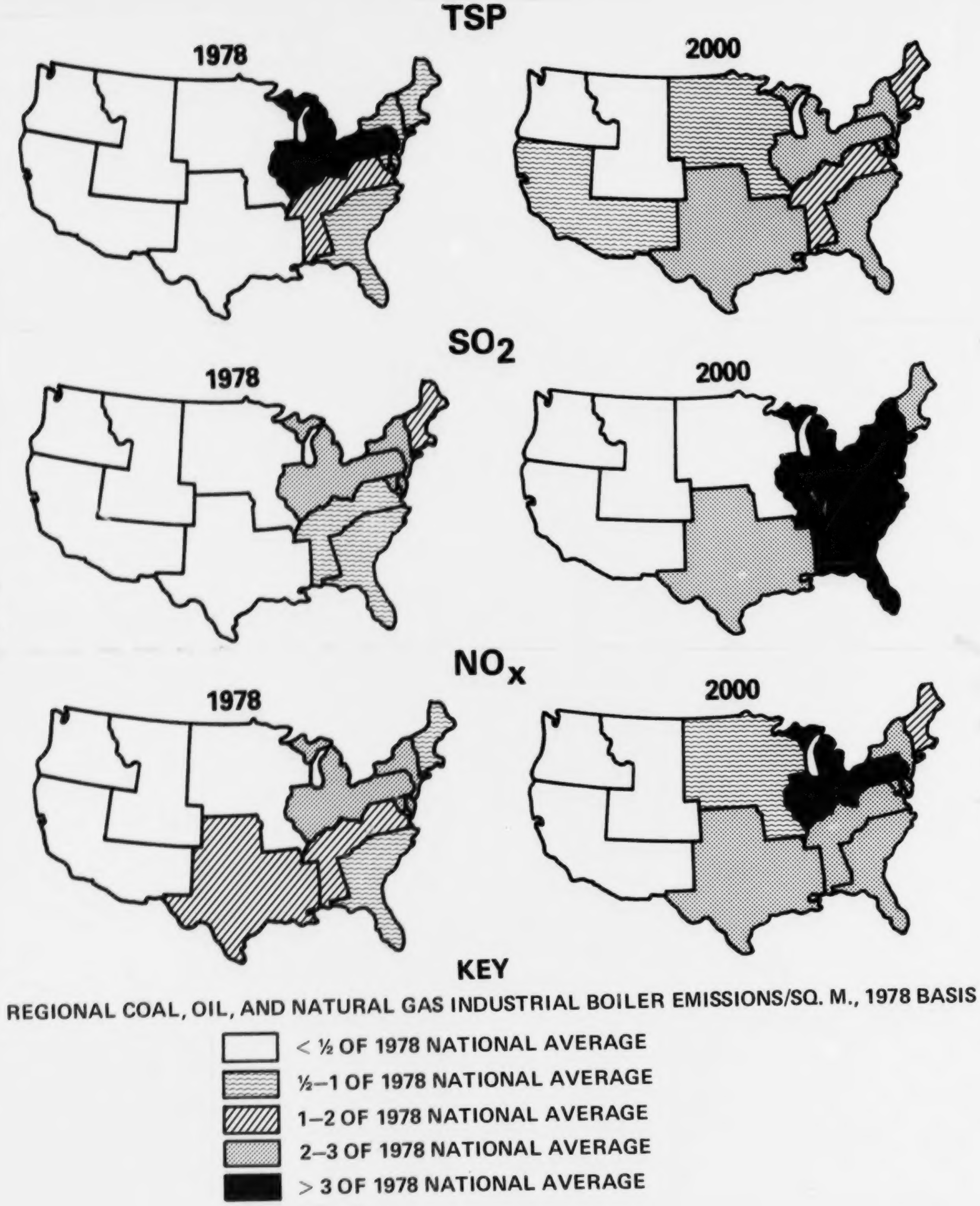
TSP
1978
2000
SO₂
1978
2000
NOx
1978
2000
KEY
REGIONAL COAL, OIL, AND NATURAL GAS INDUSTRIAL BOILER EMISSIONS/SQ. M., 1978 BASIS
< ½ OF 1978 NATIONAL AVERAGE
½–1 OF 1978 NATIONAL AVERAGE
1–2 OF 1978 NATIONAL AVERAGE
2–3 OF 1978 NATIONAL AVERAGE
> 3 OF 1978 NATIONAL AVERAGE

Figure 29. Regional distribution of industrial boiler emissions, years 1978 and 2000.

The relative importance of various regions, however, neglects the fact that emission levels as a whole would increase in the year 2000 under conditions emphasizing coal use. Thus, Figure 29 presents a general picture of declining air quality attributable to combustion in industrial boilers throughout the entire eastern United States. In 1978, the high densities of emissions were restricted for the most part to the east of the Mississippi River. By 2000, such densities extend considerably to the west, with the easternmost regions degrading further. Such trends may not indicate air quality declining as a whole, for other major categories of emission sources are not included in the analysis, and clean-up efforts in such categories may override increases from industrial boilers. But, if coal use is to be increased in industrial boilers, managing the increases in emissions will pose a significant challenge.

What emerge from the emission trends in this section are very complex patterns arising from present fuel use, future growth rates in industrial capacity, and the relative roles various fuels may play in satisfying future demand. The viability of the trends and comparisons presented is a function of current estimates of market penetration for the coal technologies, variations in the feasibility of control in the future, and the assumed growth rates for various fuels in the various regions. Still to be tested is whether coal use can, indeed, increase as much as has been postulated in this chapter. Chapter 8 provides such a test.

CONCLUSIONS

The findings in this chapter present a rather disturbing picture for increasing the use of coal in industrial boilers. Of the coal technologies investigated, ones that burn or convert solid coal at the boiler site, only low-Btu gasification is not significantly worse than natural gas or distillate oil in terms of TSP, SO_2, and NO_x emissions. And the performance of low-Btu gasification remains uncertain with respect to hydrocarbon emissions. While both flue-gas desulfurization and fluidized-bed combustion offer greatly reduced SO_2 emissions over conventional combustion of coal or physical coal cleaning, neither technology approaches the very low SO_2 emissions from natural gas, and only 90 percent control of low-sulfur coal (0.7 percent sulfur content) with FGD outperforms distillate oil. Certainly, of course, the improved emission performance of low-Btu gas, then FGD, and FBC, followed by physical coal cleaning, can reduce to varying extents the emissions burdens from the conventional combustion of coal. Also certain is that such improvements may be sufficient to allow the use of coal in some areas of the U.S.

But the ability to accommodate the increased use of coal varies considerably from region to region. Regions with marked levels of industrial development but which now rely on natural gas will be the hardest hit. The clearest example is the Gulf Coast. Other regions, such as the Great Lakes, that now contain many industries using coal, could actually experience lower emission levels if advanced technologies are pursued. Without widespread adoption of such advanced technologies, however, emission levels resulting from firing industrial boilers will climb in all regions.

To accommodate the increased SO_2 emissions from the postulated reference mix of industrial boilers in the year 2000--an increase of approximately 6 million tons to 7.5 million tons--would require reducing SO_2 emissions from existing electric utilities by about 50 percent. Such a reduction, moreover, does not account for any possible growth in the electric utility sector. Even under conditions of growth in the electric utility sector, with planned retirement of existing capacity, plus adherence to standards of performance for new sources (NSPS), existing utility sources would require a substantial degree of SO_2 control to prevent the additional SO_2 from the industrial boilers from exceeding current emissions.

A critical factor in discussing future emissions is the assumed growth rate of boiler capacity over the next 20 years. If the growth rate projected in this analysis is halved, so are the projected emission levels. Herein lies perhaps the most important conclusion of this chapter: energy conservation is the cleanest "technology" of all, especially when the reduced demand for energy (in this case, steam), is to be met through burning coal. From the perspective of air emissions, the dirtier the fuel or its conversion technology, the more important energy conservation becomes.

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CHAPTER 8

AIR QUALITY CONSTRAINTS FACING INDUSTRY

If the use of coal in industrial boilers increases, concerns about air quality will influence what technologies are favored and where they will locate. Air quality considerations may even restrain industry's ability to greatly increase the use of coal. These are hard realities for a nation seeking to decrease its energy dependence, realities that require a fresh look at how priorities for energy and its conservation are assigned, and how air quality goals are to be met.

Much U.S. industry is already located in areas with air quality problems. A massive resurgence of coal use in industrial boilers cannot be expected unless fundamental changes are made in present siting patterns. Barring changes in siting patterns, other options must be considered. Growth in the demand for fuel, especially in the energy-intensive industries, may be slowed. Advanced--and costly--coal technologies may be pursued with unexpected vigor. The priorities for fuel use embodied in the Powerplant and Industrial Fuel Use Act of 1978 may be amended. Or, new legislative warrants may be required to decrease background air emission levels from existing sources other than industrial boilers.

The analysis in this chapter focuses on present industrial development in order to delineate the air quality constraints facing industry. Two major industrial cities have been chosen as case studies for analysis: Houston and Pittsburgh. The results of the technology comparisons within the context of these two cities are then expanded to a broader context: the seven states in which 50 percent of industrial boiler capacity exists and for which Houston or Pittsburgh is the leading center of industry. Results from these investigations allow a discussion of some of the substantive issues facing industry and policy makers in satisfying the intents of both the Clean Air Act and the Fuel Use Act.

HOUSTON AND PITTSBURGH: TWO CASE STUDIES

As the largest industrial centers in their respective regions, Houston and Pittsburgh offer excellent contexts for evaluating the potential for the candidate coal technologies to meet air quality mandates while allowing growth in industrial development. The character of the cities, their industries, and their air quality situations, present interesting comparisons. As indicated in Chapter 7, the Gulf Coast, centered around Houston, is the region most likely to experience the greatest impact from increased use. And Pittsburgh has played an historic role in the setting of air quality standards, as discussed in Chapter 2.

Both Pittsburgh and Houston are in primary non-attainment for TSP, Pittsburgh being in entire non-attainment and Houston in partial non-attainment. Pittsburgh, also, is entirely in primary violation for SO_2. Both cities are heavy industrial centers, with a dominance of primary metal industries in Pittsburgh and chemical and refining industries in Houston. Forty percent of the nation's petrochemical capacity is located in the Houston area (1).

The contrast between fuel use patterns in the two cities is notable, as measured by primary energy demand: in Houston, industrial boilers burn 48 percent natural gas, 46 percent oil, and 6 percent process gas; in Pittsburgh, the figures are 69 percent coal, 18 percent natural gas, 11 percent process gas, and 1 percent oil. Primary energy demand for industrial boilers is roughly seven times greater in Houston than in Pittsburgh at present, and this is representative of the general industrial growth trends for the two cities: industry in Houston has been growing rapidly, whereas Pittsburgh has been stable.

Case Study Scenarios

In the remainder of this section, the potentials of the two cities to increase their industrial coal use are compared by means of two industrial growth and coal conversion scenarios. Construction of the scenarios depends upon information about present air quality in each location, as well as on reliable assumptions about future industrial growth in each city.

Most of our data on present air quality come from modeling. Both cities present challenges in air quality modeling, therefore raising uncertainties in the new source permitting process outlined in Chapter 3. Sea breezes are a complicating factor for Houston, while Pittsburgh is difficult to model because of its topography and river valley influences. To avoid the controversies surrounding modeling in the two cities, a simple "rollup" method* is applied to the scenarios for each city. It must be emphasized that such an approach has value in a comparative sense only, and is not intended to be predictive.

The assumptions for industrial growth in each city are based on the OBERS economic forecasts employed in Chapter 6. That is, indices of economic growth are applied to each of the SIC code industries located within each city, after a downward adjustment is made (on the order of 10 to 15 percent, depending on the particular industry) to allow for increased energy conservation (2). The NEDS data base (3) has been used for the baseline (1978) figures for fuel consumption and emissions. Boilers smaller than 10 x 10^6 Btu per hour heat input have generally been excluded from the analysis. The fuels considered are coal, oil, natural gas, and process gas. Where "other" fuels are burned (for example, wood/bark in Houston), emissions may be omitted from the 1978 baseline.

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*"Rollup" or "rollback" methods assume that concentrations of pollutants in ambient air are linearly related to emission levels in a given area. Thus, given known emissions and known ambient air quality, rollup postulates an increase in pollutant concentrations of x percent for every x percent increase in emissions; rollback postulates a y percent decrease in ambient air for a y percent decrease in emissions.

Table 26 outlines the scenarios for assumed fuel distribution patterns in Houston and Pittsburgh in the year 2000. In both cities, the relative percentage use of process gas is assumed to remain constant between now and 2000. Because the class of large boilers is already predominantly coal-fired in Pittsburgh, few additional conversions to coal could take place, and it is difficult to imagine that new capacity could be met with a higher percentage of coal-firing than already occurs. Thus, for Pittsburgh, only one scenario is presented--a continuation of the same fuel distribution as the present.

Houston presents a markedly different situation. Essentially no coal is consumed now in Houston, as oil and natural gas predominate. The contrast shown in Table 26 between Scenarios I and II in Houston is in the fuel use assumed for the class of large boilers (>100 x 10^6 Btu/hr). In both scenarios, the assumptions for the medium boiler class are the same, with the only difference in 2000 from the current situation assumed to be the conversion of 35 percent of medium boiler capacity from oil to natural gas. The class of medium boilers is assumed therefore to have no coal-fired capacity. In both the present and in the year 2000, the class of medium boilers in Houston accounts for about 14 percent of total capacity in industrial boilers. The difference between Scenarios I and II is in the amount of conversion from natural gas to coal in existing capacity, and in the relative degree to which new capacity is fired by natural gas or coal, for the large size class of boilers. Essentially, Scenario I represents greater firing of natural gas, and Scenario II, greater firing of coal. In both scenarios, the importance of oil is assumed to decline.

The primary energy demand for industrial boilers that results from the above assumptions is displayed in Table 27. Present energy consumption is also shown for comparison. In Houston, the assumed growth between now and 2000 is 64 percent; in Pittsburgh, 34 percent. These differences in assumed growth derive from the different growth rates for the types of industries in each city, as explained previously. It should be noted that the differences in growth will result in a slightly more favorable picture for Pittsburgh than for Houston in the comparisons presented below.

In the comparisons, each of the following coal technologies is assumed to deliver all of the assigned coal demand in each city and in each scenario: conventional combustion (CC); physically cleaned coal in conventional combustion (PCC); flue-gas desulfurization with conventional combustion (FGD); fluidized-bed combustion (FBC); and low-Btu gasification. The assumption that all coal-firing would be met entirely with one technology is unrealistic, but does allow greater comparisons between technologies than would a comparison of

TABLE 26. ASSUMED FUEL USE IN INDUSTRIAL BOILERS IN HOUSTON AND PITTSBURGH FOR THE YEAR 2000

	Large boilers ($>100 \times 10^6$ Btu/hr)		Medium boilers (10 to 100×10^6 Btu/hr)	
	Conversion of Existing Capacity	New Capacity to 2000	Conversion of Existing Capacity	New Capacity to 2000
Houston				
Scenario I	80% of oil converted to coal 10% of natural gas converted to coal	10% oil 48% coal 38% natural gas 4% process gas	35% of oil converted to natural gas	87% natural gas 10% oil 3% process gas
Scenario II	80% of oil converted to coal 65% of natural gas converted to coal	10% oil 72% coal 14% natural gas 4% process gas	Same as Scenario I	Same as Scenario I
Pittsburgh				
Scenario I	None (71% already coal-fired)	71% coal 12% natural gas 17% process gas	None	58% coal 30% natural gas 11% oil 1% process gas

TABLE 27. PRESENT AND ASSUMED PRIMARY ENERGY DEMAND IN MEDIUM AND LARGE* INDUSTRIAL BOILERS FOR HOUSTON AND PITTSBURGH (10^{12} Btu)

Case	Coal	Natural gas	Oil	Process gas	Total
Houston					
Present	0	147.4	139.4	18.5	305.2
Scenario I	202.5	224.5	47.4	27.2	501.6
Scenario II	303.8	123.2	47.4	27.2	501.6
Pittsburgh					
Present	30.2	8.1	0.5	4.9	44.0
Scenario I	44.3	8.7	0.9	5.1	59.0

*See text for size definitions.

mixes of technologies. To account for differences in efficiency between the technologies, the steam produced by conventional combustion is specified as the delivered energy to be satisfied by each of the technologies in the comparisons. Removal efficiency of TSP in all technologies is 84 percent. Eastern coal is assumed for both Houston and Pittsburgh. All other technology assumptions are the same as those outlined in Chapter 6.

The oil, natural gas, and process gas emissions from industrial boilers are assumed to follow the simple ratio of future-capacity/present-capacity for each fuel. Industrial process (non-boiler) emissions increase linearly with respect to the assumed boiler consumption growth rates. All other categories of point source and area source emissions remain unchanged in 2000 from 1978; this will result in an underestimation of uncontrolled emissions in the future that come from ancillary growth. Area sources--such as automobiles, homes, commercial establishments, fugitive dust, and pollutants generated elsewhere but transported into the cities--are also excluded from the analysis.

Growth May Be Constrained

Because Pittsburgh is in non-attainment for TSP and SO_2, and Houston is in non-attainment for TSP and could (under certain conditions of fuel usage now allowed there) also be classified as in non-attainment for SO_2 (1), both areas are required to demonstrate reasonable further progress towards attainment of the national standards for ambient air quality (NAAQS) under Sec. 172 of the Clean Air Act. As detailed in Chapter 3, "reasonable further progress" means that the air must be made cleaner by a set date. Generally, the mechanism for achieving such progress is to reduce the emissions from existing sources. If new sources of emissions are to be allowed, then the amounts and types of emissions from existing sources will need to be reduced. Thus, growth is allowable only when existing sources are controlled to bring the ambient air quality into attainment, and additional controls are applied to make up the added contribution from the new sources.

Without extensive modeling, it is impossible to know what reductions of emissions might be required in Houston and Pittsburgh to bring them into attainment for the air quality standards. So, instead of attempting to define what would constitute reasonable further progress in each city, we assumed that their present emission levels were inviolable ceilings that could not be exceeded in the future.

Table 28 presents the 1978 point source emissions for Houston and Pittsburgh and for the postulated growth conditions to the year 2000, excluding the emissions from coal-fired industrial boilers. An increase of approximately 40 to 50 percent in non-coal boiler emissions occurs in Houston to the year 2000; a 15 to 20 percent increase is expected for Pittsburgh. Emission increases for non-industrial sources were not incorporated into the estimates.

When the emissions from the various coal technologies are added to the above emission levels for the year 2000, the percent changes in total point source emissions are obtained (Table 29). Any figures in Table 29 showing an increase of over 100 percent mean that the growth level postulated cannot be obtained by utilizing that particular coal technology; it is not possible to eliminate all existing emissions to accommodate growth.

The picture is questionable for Houston. Under the conditions assumed, none of the coal technologies is sufficiently clean. Although improvements could be gained in SO_2 emissions if low-sulfur coal were used exclusively (rather than Eastern coal with 3.5 percent S content), TSP emissions would still be at unacceptable levels. The differences in TSP emissions for the two technologies with the best SO_2 performance using low-sulfur coal--low-Btu gasification and FGD--are inadequate to counteract the percent TSP increases noted in Table 29.

The results for Houston are supported by other evidence. A recent report to the Texas Air Control Board indicated that if all the dual-fired facilities now burning gas switch to fuel oil, the Houston area would be in non-attainment for SO_2 (1). Such fuel switching was exempted from PSD review by the EPA. With a switch to fuel oil, the report indicated that allowable SO_2 concentrations (in ambient air, not emissions) would need to be reduced 65 percent if Houston remained in PSD Class II for SO_2 or 45 percent if Houston were re-classified to non-attainment. Both reductions were contingent upon limiting future oil sources. Coal was not investigated, but certainly greater reductions would be necessary if coal were burned.

In the case of Pittsburgh, the percent changes shown in Table 29 are more promising. Conventional combustion and the physical cleaning of coal would add one-fourth to one-half to SO_2 levels, but FGD, FBC, and low-Btu gasification would result in a net improvement in SO_2. The TSP levels for all the technologies are potentially acceptable. Apparently, three of the five technologies could be utilized while still allowing growth.

However, the situation may be more complex than it initially appears. First, the percent changes indicated in Table 29 are based on present emission levels and not on actual attainment of the air quality standards. In fact, a recent analysis of various SIP options for Allegheny County indicates that Pittsburgh cannot attain TSP standards even with the application of reasonably available control technology (RACT) on all existing sources (4, 3), without even considering emissions from possible new sources. Second, this analysis

TABLE 28. PRESENT AND YEAR 2000 POINT SOURCE EMISSIONS FOR HOUSTON AND PITTSBURGH (10^3 TONS/YR)

	Present		Year 2000	
	TSP	SO_2	TSP	SO_2
Houston				
Scenario I				
Industrial coal boiler	>0.1	>0.1	see text	
Industrial oil boiler	1.3	6.3	0.4	2.1
Industrial natural gas boiler	1.4	5.9	2.1	9.0
Industrial process gas boiler	>0.1	4.7	>0.1	6.9
Industrial processes	31.8	125.7	52.2	206.2
Non-industrial point	1.2	7.1	1.2	7.1
SUBTOTAL	35.8	149.7	56.0[a]	231.3[a]
Scenario II				
Industrial coal boiler	as above		see text	
Industrial oil boiler			0.4	2.1
Industrial natural gas boiler			1.1	5.0
Industrial process gas boiler			>0.1	6.9
Industrial processes			52.2	206.2
Non-industrial point			1.2	7.1
SUBTOTAL			55.0[a]	227.3[a]
Pittsburgh				
Scenario I				
Industrial coal boiler	4.3	51.4	see text	
Industrial oil boiler	>0.1	0.1	>0.1	0.1
Industrial natural gas boiler	>0.1	>0.1	>0.1	>0.1
Industrial process gas boiler	0.1	>0.1	0.1	>0.1
Industrial processes	44.2	92.6	59.3	124.0
Non-industrial point	43.5	99.5	43.5	99.5
SUBTOTAL	92.1	243.6	102.9[a]	223.7[a]

[a] Excludes emissions from coal-fired industrial boiler. See text and Table 26.

TABLE 29. PERCENT CHANGE IN EMISSIONS FROM POINT SOURCES IN HOUSTON AND PITTSBURGH BETWEEN 1978 AND 2000, ACCORDING TO COAL TECHNOLOGY

	TSP	SO_2
Houston		
Scenario I		
Conventional combustion	181	443
Physical coal cleaning	110	293
Flue-gas desulfurization	178	93
Fluidized-bed combustion	185	82
Low-Btu gasification	96	78
Scenario II		
Conventional combustion	245	634
Physical coal cleaning	138	422
Flue-gas desulfurization	240	110
Fluidized-bed combustion	250	93
Low-Btu gasification	117	88
Pittsburgh		
Scenario I		
Conventional combustion	7	44
Physical coal cleaning	1	24
Flue-gas desulfurization	7	-3
Fluidized-bed combustion	7	-4
Low-Btu gasification	1	-5

does not incorporate non-point emissions. Fugitive dust levels in Pittsburgh are very high. Upwind transport of SO_2 from major sources in the Ohio River Valley contributes about 25 ug/m^3 (about one-third of the allowable SO_2 ceiling under NAAQS) to background levels in Pittsburgh (4). Credit for certain non-urban background contributions of TSP may be granted in an SIP, but SO_2 transported from other areas may not. Third, the age of much of Pittsburgh's industry makes achieving standards by retrofit control very difficult. The potential for controlling other industrial process emissions, such as coke ovens, is also an area of uncertainty.

Areas with extensive industrial development that rely on the use of clean fuels, such as Houston, would be hard-pressed to accommodate growth and use coal at the same time. Somewhat paradoxically, areas such as Pittsburgh, which may benefit from replacing dirty coal technologies with cleaner ones, may have growth constrained in other respects--by the age of industry, long-range transport of pollutants, and already heavily polluted air.

A BROADER VIEW: 50 PERCENT OF INDUSTRIAL BOILER CAPACITY

Two Major Industrial Belts

In a sense, Houston and Pittsburgh embody many of the similarities and differences between the two great industrial belts of the Gulf Coast and Great Lakes. The states that make up these industrial belts, the level of their industrial development, and the status of their air quality are the topics of this section. As the chosen locations for many of the nation's major, energy-intensive firms, the seven states comprising the Gulf Coast and Great Lakes industrial belts provide the toughest test of air quality constraints on increased use of coal for industrial boilers.

The Great Lakes Industrial Belt--including the five states of Indiana, Illinois, Michigan, Ohio, and Pennsylvania--consumes 40 percent of all coal, and 20 percent of all oil and natural gas used in the United States for industrial boilers. Emissions percentages are even higher, with over 40 percent of the total SO_2 and TSP, and over 25 percent of the NO_x emitted from industrial boilers nationwide. Texas and Louisiana*, which comprise the Gulf Coast Industrial Belt, consume about 40 percent of the natural gas used in industrial boilers. Industrial boilers also consume a fair amount of oil, approximately 9 percent of the national total, with a small coal contribution, predominantly lignite. About one-quarter of NO_x emissions from industrial boilers occur in Texas and Louisiana, with about 8 percent of all TSP and 6 percent of all SO_2. Combined, the two industrial belts represent approximately 50 percent of fuel usage and emissions from industrial boilers. Table 30 documents the fuel use and emissions in the seven states. In terms of air quality, the Great Lakes Industrial Belt is the dirtiest in the country; in the Gulf Coast Belt, most counties are in attainment for TSP, and no areas violate the NAAQS for SO_2.

Industrial Concentration Corresponds to Dirty Air**

A county-by-county investigation of air quality status and industrial boiler emissions in locations in the seven states comprising the two great industrial belts shows both that industry is heavily concentrated in those states and that much of existing boiler capacity is located in non-attainment areas. Approximately 90 to 95 percent of major industrial boiler capacity is located in counties comprising one-sixth of the total land area in the two industrial belts; 65 to 75 percent of total industrial capacity occurs in counties comprising less than 4 percent of the total land area. For example, in the Great Lakes Industrial Belt, much more than half of industrial capacity as measured by emissions occurs in twenty-two of 436 counties, and about 90 percent of capacity occurs in about eighty-five counties. Similar patterns of concentration are found in the Gulf Coast Industrial Belt.

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* Note that the Great Lakes Industrial Belt is the same as the CTA Region III, the "Great Lakes." The Gulf Coast Industrial Belt is a part of, but not as large as, the "Gulf Coast" CTA Region VI. Consistent with the approach of the Coal Technology Assessment, regions are defined according to the analysis at hand.

** Supporting material for the findings presented in this section may be found in Appendix C.

TABLE 30. INDUSTRIAL BOILER FUEL AND EMISSION CHARACTERISTICS FOR TWO MAJOR INDUSTRIAL BELTS (5)

	Fuels						Emissions					
	Coal		Oil		Natural Gas		TSP		SO_2		NO_x	
	10^5 Tons	% of U.S. Total	10^6 Gallons	% of U.S. Total	10^9 SCF	% of U.S. Total	10^3 Tons	% of U.S. Total	10^3 Tons	% of U.S. Total	10^3 Tons	% of U.S. Total
Great Lakes Industrial Belt												
Illinois	37.0	6.9	485.0	3.6	156.5	4.5	87.5	8.4	213.8	6.3	66.5	3.6
Indiana	22.5	4.2	538.0	4.0	83.4	2.4	19.8	1.9	154.0	4.5	123.4	6.6
Michigan	42.8	7.9	319.2	2.4	136.0	3.9	29.8	2.9	123.9	3.6	68.7	3.7
Ohio	67.7	12.6	404.8	3.0	162.4	4.7	135.6	13.0	385.5	11.3	152.6	8.2
Pennsylvania	43.7	8.1	742.0	5.5	180.0	5.2	182.9	17.6	520.6	15.3	84.6	4.5
TOTAL	213.7	39.7	2489	18.5	718.3	20.7	455.6	43.8	1397.8	41.0	495.8	26.6
Gulf Coast Industrial Belt												
Louisiana	0.9	0.2	1039.4	7.8	870.1	25.1	38.3	3.7	77.9	2.3	216.9	11.6
Texas	13.4	2.5	106.3	0.8	524.2	15.1	41.1	4.0	122.8	3.6	231.8	12.4
TOTAL	14.3	2.7	1145.7	8.6	1412.3	40.2	79.4	7.7	200.7	5.9	448.7	24.0
GRAND TOTAL	228.4	42.3	3635	26.9	2112.8	60.6	535.0	51.5	1598.9	47.2	944.5	50.2

More importantly, counties with high levels of industrial boiler capacity also tend to be in non-attainment for the national standards for ambient air quality. Overall, about 65 to 75 percent of industrial emissions from boilers in the seven states come from counties in primary or secondary non-attainment for TSP or SO_2. In the Great Lakes Industrial Belt, about 85 percent (by capacity) of major industrial boilers are located in TSP non-attainment counties, with figures as high as 98 percent in Ohio. One-third of SO_2 emissions from industrial boilers in this belt take place in counties in primary non-attainment for SO_2. Approximately 15 to 20 percent of the Gulf Coast's industrial boiler capacity is located in counties with TSP violations.

Furthermore, many of the other counties with high levels of industrial boiler emissions have insufficient data to demonstrate attainment for the NAAQS. For example, over 150 counties in the seven states investigated show high levels of emissions from industrial boilers (see Appendix C to find how such levels were determined). Only five of these 150 counties have sufficient data to verify attainment status for TSP and SO_2. Of the over 145 counties remaining, 60 percent are in non-attainment for TSP or SO_2; 40 percent have had no air quality monitoring, show possible violations, or are unclassified. Thus, the correlation between industrial concentration and dirty air may be even stronger than the available data can indicate.

Other portions of this report explain why industrial development occurs where it does: access to markets and raw materials, availability of transportation, the attraction of cheap and plentiful fuels, requirements for skilled labor, perhaps even "business climate." Whatever the reasons, however, industrial development in the seven states of the Great Lakes and Gulf Coast Industrial Belts has tended to settle in a relatively few concentrated pockets. The implication for industry is that the factors historically considered in siting plants may be obsolete. If coal use in industrial boilers is to be increased, the imperatives of meeting air quality constraints will absorb increasingly larger amounts of the firms' management and planning attention. Moreover, conversion or replacement of existing capacity by coal appears severely limited for the seven states investigated.

POPULATIONS AT RISK

One of the main points of the historical overview presented in Chapter 2 is that it is the perception of changes in air quality, not the absolute quality of the ambient air, which most leads to public outcry. The previous section demonstrated that, at least for 50 percent of the nation's energy-intensive industries, industrial development is highly concentrated. What such concentration means in terms of placing populations at risk from air pollutants, and what such risks may mean, in turn, about the public acceptability of a widespread shift to the use of coal in industry, is the topic of the present section.

It is widely commented that industry is essentially urban, though clear data to support such an assertion have been lacking. Two very different but complementary approaches were taken to answer the question about the urban character of industry. The first approach used NEDS, while the second approach related the emission densities discussed in the previous section to population densities.

Point sources included in NEDS are coded with a number of geographical identifiers, including location by county and location within city limits for cities with populations over 2,500. In addition, OAQPS had already identified and selected counties nationwide that comprise the 105 urban areas exceeding 200,000 in population (5). The purpose of selecting these counties was for the possible establishment of a vehicle inspection and maintenance program under Sec. 172(b) of the Clean Air Act. Thus, the means existed at the outset of our analysis for allocating emissions from industrial boilers into three categories: rural, city, and urban. The "cities" category was obtained by its appropriate identifier in NEDS; that is, boiler emissions were placed in the "city" category if the source of the emissions was located within the incorporated limits of a city greater than 2,500 in population. Assigned to the "urban" category were emissions from boilers located in the counties comprising the 105 urban areas defined by OAQPS.* While incorporated city limits and county boundaries of course do not always coincide, for all intents and purposes, the "urban" category may be seen as a subset of the "city" category. The "rural" category is defined as all emissions not in the other two categories.

The pie charts in Figure 30 present the results of allocating the emissions from industrial boilers into the three categories. The shares for each of the three categories in each pie chart represent the average of the percent shares from TSP, SO_2, and NO_x emissions. Lumping the figures for the three emission types provides an excellent surrogate for boiler capacity. For the entire U.S., about one-third of emissions from large boilers occurs rurally, two-thirds occur in cities, and about one-fourth occurs in the 105 urban cities.

Considerable variability exists between regions. Urban capacity is very large in the Great Lakes and Upper Atlantic regions, very low in New England and the Great Plains, and much lower than average (but roughly consistent) in the Pacific Northwest, Gulf Coast, Appalachia, and Southeast. Urban emissions are close to average in the Rocky Mountain and Pacific Southwest regions. Interestingly, though, the latter two regions have considerably more rural capacity than average, as does the Southeast. Rural emissions are considerably below average in New England and the Upper Atlantic; the city/rural breakdown is close to average in the remaining five regions. Apparently, no region is "typical" of the total breakdown for the U.S. Certain regions, though, are quite typical in one or two of the three categories.

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*The "urban" category could have been defined in a number of ways: by Standard Metropolitan Statistical Area (SMSA), by city limits for those cities over a given population; or by county boundaries that by some other criterion are classified as urban. Each approach has a number of drawbacks in the effort to account properly for the urban character of an area. The OAQPS approach was chosen because of its real relationship to the CAA, and because the boundaries of many SMSAs incorporate much rural area.

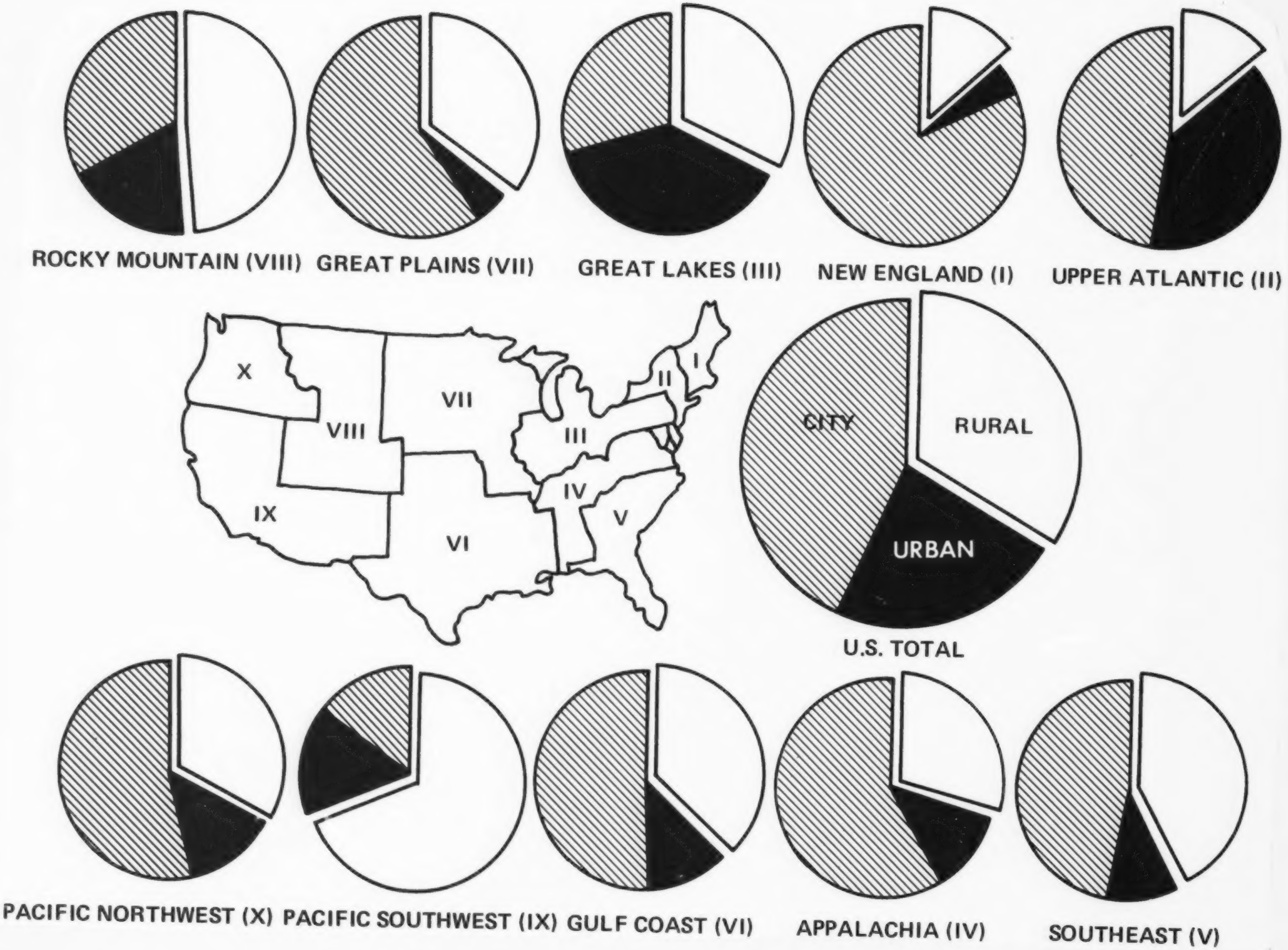

Figure 30. Urban-city-rural breakdown of industrial boiler emissions, 1978.

Altogether, rural emissions appear somewhat higher than observation or intuition might suggest. Of course, rural industries can play quite a significant role in overall emissions, yet not be so obvious as those industries located near population centers (this same factor may also skew the quality of emission inventories). Also, rural industries may be fewer in number, but larger in capacity because they are not so constrained by the environmental and site-specific considerations inherent in municipal localities. Certain kinds of industries, too, tend to be rurally located. By and large, however, the municipal location of industry is supported by the data, with a few regions being a bit more "rural" in nature. Moreover, in a number of respects, the definition of the categories employed in the analysis may be masking the reality. For example, concentrated industrial areas, located near urban areas but outside incorporated city limits or in adjacent counties, may be classified as rural. Similarly, common experience indicates that substantial industrial capacity, particularly for larger cities in the "cities" category, may be located in municipal settings and yet not be within city limits. Part of the ambiguity results from different interpretations of the terms rural, municipal, and urban.

Approaching the question of the relationship between industrial development and population density in a different manner leads to the figures shown in Table 31. Building on the previous selection of the counties in the two industrial belts that experience high emission levels from boiler combustion, Table 31 demonstrates that the same counties are also densely populated. Over 60 percent of the total population in the two industrial belts reside in those counties with high densities of emissions from industrial boilers. Over one-quarter reside in counties with the highest densities. In fact, emissions per person are roughly double the average of the industrial belts in the high emission counties and triple the average in the highest emission counties. Considerable variation exists between states, however, as the 1975 figures in the table suggest.

In those areas where natural gas is dominant, shifting to coal could be widely perceived as degrading the air quality, even if all applicable environmental regulations were met (6). Thus, public acceptance may be a factor in the choice of boiler feedstock. If deteriorating air quality is perceived to affect property values, the industrial energy manager may need to worry more about public opposition than acceptance. Where well-controlled coal capacity is replacing uncontrolled existing coal capacity, the public perception may be one of net benefit, as long as costs of goods delivered in the local marketplace do not rise substantially.

The groundwork is now almost complete for discussing the accommodation of new growth under conditions emphasizing the increased use of coal in boilers. Factors of public acceptance, the concentration of industry, and shifting regional burdens have been presented, as well as comparative analyses of coal technologies. The next section addresses the remaining, missing piece: the regulatory options in managing growth and coal use.

TABLE 31. POPULATIONS AT RISK IN COUNTIES WITH HIGH INDUSTRIAL EMISSION DENSITIES IN THE TWO INDUSTRIAL BELTS

State	Total population[a] (10^6)	Population in high emission counties (%)	Population in highest emission counties (%)
Great Lakes Industrial Belt	49.25	64	28
Illinois	11.21	74	6
Indiana	5.31	44	11
Michigan	9.12	63	28
Ohio	10.74	72	46
Pennsylvania	11.86	63	33
Gulf Coast Industrial Belt	16.03	58	20
Louisiana	3.80	56	25
Texas	12.24	59	19
TOTAL BOTH BELTS	65.28	63	26

[a] 1975 basis.

EMISSION OFFSETS: WILL THEY WORK FOR INDUSTRY?

Emission offsets refers to a policy adopted by the EPA in December 1976 (7), and later incorporated into the Clean Air Act and Amendments of 1977, in which new major sources desiring to locate in a non-attainment area must reduce emissions of the pollutant for which the area is in non-attainment at an amount equal to or greater than the new emissions the proposed facility would contribute. Documented agreements to obtain such reductions are required before a construction permit may be granted. Actual emission reductions must be documented before the new facility may begin operation. Offsets are only valid for the same pollutant (in all but two states); reductions, say, in NO_x emissions may not be applied to SO_2. Two types of emission offsets are recognized. "Internal" offsets are reductions in emissions from the same facility. "External" offsets are reductions from other sources. The policy of emission offsets was adopted to respond to growing fears that the non-attainment designation would preclude economic growth until attainment of the NAAQS.

While the EPA has recognized other approaches to accommodating growth in non-attainment areas, such as "growth allowances" (see Chapter 3), which may be specified in a state implementation plan, offsets remain the dominant mechanism. Apart from questions of whether growth is desirable in non-attainment areas, this section investigates the efficacy of the offset policy for both allowing growth and improving air quality. The investigation is set in the framework of greatly increased coal use in industrial boilers.

Status of Offset Permits

Until August 1979, approximately 500 permits for new or modified sources had been issued under the federal emission offset policy; over 95 percent of these permits used internal offsets (8). The offset procedure has been employed to date in thirty-four states. Of the fifty states, twenty-four have provisions for both the growth allowance and emission offset policies; sixteen states incorporate emission offsets only; four states have only a growth allowance policy; and four states have neither (8). For the eight states that now have no policies for emission offsets, four have had in the past and the remaining four are largely in attainment for the NAAQS.

Applicability of the offset policy is not confined solely to non-attainment areas. As reviewed in Chapter 3, prevention of significant deterioration (PSD) policies also establish increment ceilings for increases in pollutant levels in the ambient air. For any given PSD Class I, II, or III area, once the ceiling has been reached, new or modified sources in the area would also have to offset their emission contributions by reducing emissions from existing sources. In one case, a PSD offset has already been obtained (8). Over time, as development proceeds in PSD areas, the role of emission offsets should become more important. Thus, while the offset policy was initially formulated to deal with non-attainment areas, its scope may become nationwide.

The ability of internal offsets alone to accommodate development is inherently limited. By definition, internal offsets must come from facilities owned by the same firm in the applicable area. In a given area, one firm emits only so much of a given pollutant. If the internal offset is to be used for expansion of the same facility from which the emission reductions are made, the expansion will be limited (apart from other factors such as space limitations--see Chapter 4) by the technological feasibility of controlling the pollutant under consideration. Under conditions where, for example, a coal-fired boiler is to be added to a facility now burning natural gas or distillate oil, there may be no SO_2 emissions that could be reduced. Nevertheless, of course, internal offsets can be important. But when new firms desire to locate in an area with dirty air, or if individual firms do not themselves have the potential to reduce emissions of the same type, external offsets are the key to the efficacy of the offset policy.

The fifteen or so external offsets to date have been obtained largely for smaller sources (8). More extensive use of external offsets appears to be limited because of the attitudes of industry and the uncertain "value" of emission reductions in the marketplace. If coal use is to be increased, particularly in regions of the U.S. where coal use has been limited, finding external offsets will be critical.

Industry Attitudes and Uncertainties

When it was first enacted, the emission offset policy was received by industry as an important step forward in the philosophy of regulation. It made the resource of clean air a valuable commodity, to be bought and sold in the marketplace according to familiar economic principles. In the words of one observer of industry (9):

> "By seriously considering and accepting some market approach to the allocation of air quality, the EPA has shown official recognition of the arguments for cost effectiveness that economists and others have put forward for many, many years. Few notions enjoy such widespread acceptance among economists as the potential resource savings that might spring from using a price system to allocate scarce goods. As opposed to uniform, hard-and-fast regulations, a system of emission fees or marketable permits would enable each decision maker to assess his or her particular environmental situation and to seek out the cheapest approach to its solution."

Yet, apparently, external offsets--the buying and selling of potentials for emission reductions between firms--have not come into widespread use. Perhaps the most important reason is the unwillingness of firms to give up their potential for emission reductions. Plans for expansion in individual firms may hinge on the ability to make internal offsets in the future. By allowing other firms--perhaps even competitors--to place controls now on their controllable emissions, a firm may, itself, be unable to find external offsets at a later date. As states attempt to bring their non-attainment areas into compliance, existing facilities will become increasingly well-controlled, with the most easily controlled and polluting sources handled first. Emissions available for reduction under offset policies will become increasingly hard to find and more expensive to control. To build a new facility, especially one using coal, may require emission reductions from a number of existing sources, which could lead to complicated arrangements and documentation and, hence, what could be perceived as a significant diversion from the firms' main interests.

The reluctance of firms to make emissions available to other firms under offset has been validated by a number of disparate sources. Representatives of the Texas Air Control Board have noted that new "grassroots" industries have had difficulty siting in the Houston area because the existing firms have been unwilling to give up offset potential (10). In the Bay Area in California, the same reluctance has been found by the local air pollution control agency (11). Another study, a broad survey of offsets to date (8), indicates that of the firms and agencies contacted in the survey, more anticipated that the offset market would shrink and vanish within a few years than that it would expand. Indeed, the survey also found that the industrial managers, engineering consultants, and attorneys contacted often knew of many projects that had been deferred or abandoned for lack of suitable offsets. Furthermore, an unanticipated side effect of the offset policy may be for firms to inflate their estimates of current emissions: "Nationally, there probably will be sudden upward revisions of emission inventories for past years; the 'in' thing now is to build an emission bank account for offset use. In years past companies strived to minimize the reported emissions for their facilities to try to prevent adoption of additional control measures!" (11)

The uncertainties surrounding the future availability of emission reductions, as well as other factors, make setting a "value" on offsets extremely difficult. In many cases, the purchase price for emissions may be greater than the cost of controlling the emissions themselves (11). There are also difficulties in identifying suitable parties to negotiate with for offsets, which may require advertising or employing a broker. And, of course, the "value" of clean air is also not uniform throughout the nation, which makes establishing meaningful benchmarks from prior offset agreements problematic for firms contemplating their own negotiations.

Total costs, therefore, for offsets may be quite high, yet may be hard to account for in the corporate decision-making process. There are the costs for control itself, for engineering, advertising, negotiating, monitoring if required, options if exercised, taxes, and opportunity "costs" (8). Moreover, the costs of offset do not equal its price, for the seller will figure in a profit margin as well to account for his own opportunity costs. In time, too, the worth of the goods--that is, "available" clean air--can be expected to increase, thus increasing the price of offset in a classic market environment.

Thus, obtaining offsets, especially external ones, is not promising. Expanding the use of coal in areas now in non-attainment, or which have little increment available under PSD, faces real constraints. And the magnitude of the problem can be expected to increase.

Clean Air as a Finite Resource

Essentially, PSD and non-attainment provisions make clean air a valuable resource, with "emission reduction potentials" a valuable commodity. In fact, options other than offset that are available to the states, such as emissions "banking" and marketable permit systems ("pollution rights"), capitalize on this relationship. A "growth allowance" approach is an extension of the same principle, though perhaps is more equitable, since smaller sources themselves may not need to obtain offsets. This fundamental principle--that clean air is a finite and unconcentrated resource--has direct implications for increased coal use in a concentrated and geographically restricted industrial sector.

First, as discussed in previous sections, significant emission increases can be expected from high levels of coal use in industrial boilers over the next two decades. Regionally, such increases may be very much greater than the national average, particularly in the Gulf Coast, Southeast, and Pacific Southwest. Some of the more costly (see Chapter 10) coal technologies investigated promise somewhat improved emissions performance; however, the costs of the technologies must also be incorporated into the price of offsets. With marked emission increases, the need for offsets or other mechanisms to reduce emissions will be increased.

Second, much of the present industrial capacity is located in non-attainment areas. If offsets or similar measures cannot be obtained, costly plant relocations will be required for new industrial development. Industries not now in non-attainment areas may also face restrictions because of emission limitations under PSD policies.

Third, accompanying the growth of industry is ancillary development that creates new sources of area emissions such as vehicles and homes, as well as smaller point sources not covered in the CAA. As policies are presently constructed, large stationary sources will also have to reduce their own emissions further to account for the new emissions from the ancillary development. If adequate control cannot be managed, reasonable progress towards attainment will not be made, and industrial growth will be halted.

Fourth, the impacts will be different for various industries and for the size of industry. Small sources, not now covered by the CAA, can get by the requirements. Very large facilities or facilities that are locally important employers may already have large internal offsets, or they are more visible, can better afford consultants, or can better afford to pay the price of offsets. It is the firms in between these two extremes of size and employment that may bear the greatest relative burden. Liable to regulation, yet less visible and perhaps operating on smaller margins of profit, the intermediate firms may be faced with an untenable dilemma: relocate plants or pay the price of offsets, if available.

ACCOMMODATING NEW GROWTH

The foregoing analysis allows a number of conclusions regarding the use of coal in industrial boilers. The conclusions range from the national to the regional, to the choice of coal technologies, and to the longer range implications of some of the U.S.'s present energy and environmental policies. Pivotal to an expansion of coal use in the industrial sector will be the ability of industry to meet provisions of the Clean Air Act under present siting patterns or, failing that, to have access to the financial resources necessary for facility relocation.

Present fuel use patterns and growth will create regional inequities in the distribution of emissions from coal combustion in industrial boilers. The urban character of industrial development will, in turn, have an impact on populations at risk. Thus, public opinion could play a prominent part in acceptance of expanded coal use. Future growth of coal use in industrial boilers, as well as the area in which a particular industry desires to locate, will be a function of such acceptance.

PSD vs. Non-Attainment

An overwhelming percentage of the existing industrial capacity in the Great Lakes and Gulf Coast Industrial Belts is located in non-attainment areas. The types of constraints and administrative procedures under PSD are considerably different from those for non-attainment. Because of these differences, future growth in certain areas may be less curtailed under non-attainment than under PSD. Growth in either area, however, will eventually be predicated on decreasing emissions from existing sources.

New major sources or modifications may not be constructed or begin operation in a PSD area where the allowable increment (19 ug/m^3 for TSP, 20 ug/m^3 for SO_2 in Class II areas on an annual basis) is exceeded. Only when new emissions fall within the limits set by the increment and the NAAQS, can growth occur. Compliance is predicted by modeling. EPA presently administers PSD permitting (states soon are to incorporate PSD maintenance in their SIPs) and sets guidelines for the use of models and for validating air quality monitors.

New construction can also be prevented in non-attainment areas. However, as long as reasonable further progress toward attaining the NAAQS and BACT are being applied under an approved SIP, growth may occur. Attainment must occur by 1983 for those areas already classified in non-attainment for TSP or SO_2, or within three to five years (depending on certain restrictions) for redesignated non-attainment areas. EPA has been carefully screening SIP submittals. After approval, SIPs are administered by each state. Attainment of the NAAQS is measured by monitoring in conjunction with modeling, but compliance with reasonable further progress for an SIP is generally demonstrated by "pound for pound" emission reductions from larger sources. Because of this approach, an emphasis has been placed on offsets for new and modified sources and RACT on existing sources in non-attainment areas.

Modeling and monitoring introduce delays into the permitting process. In general, because of the emission reduction approach in non-attainment areas, internal offsets introduce the fewest delays. Modeling and up to one year of monitoring may be required in PSD areas. While guidelines exist for models, the particular circumstances in a given situation may justify creating new models appropriate to the circumstances. Such circumstances include topography, breezes, and other unusual meteorological events. Model assumptions, in all cases, must also be made concerning background concentrations, plume rise and dispersion, half-life of compounds, actual vs. allowable emissions, stack heights, and so on. Adequate and proximate meteorological information must also be made available. Under mandates of the Fuel Use Act, delays in permitting may actually be advantageous to the firm desiring not to use coal. Thus, differences in delays imposed by the different administrative procedures for PDS and non-attainment areas may be insufficient to prove one area more attractive for future development than others.

Over the short-term, non-attainment areas, with their many point sources, offer more opportunities for emission reductions than do PSD areas. However, as existing facilities and easily controllable sources of fugitive emissions become controlled, fewer emission reductions will be available for new or modified sources. In view of the likelihood that, over time, non-attainment areas will be increasingly less attractive for new development, and that insufficient increments will exist in PSD areas to allow concentrated development, increased use of coal in industry based on air quality considerations can be ranked for various areas. The ranking considers new capacity as well as boiler replacement. These areas are, in descending order of attractiveness:

1. Class II PSD areas with large available increments
2. Class II PSD areas with moderate NO_x emissions, large TSP and SO_2 increments
3. Class II PSD areas with moderate TSP and SO_2 increments
4. Non-attainment areas with large existing coal capacity
5. Non-attainment areas with large oil capacity
6. Non-attainment areas with large natural gas capacity
7. Class II PSD areas with little available increment
8. Class I PSD areas.

Recall that 75 percent of industrial boiler capacity in the two industrial belts occurs in counties covered by ranks 4 through 6. Apparently, much of the remaining capacity occurs under rank 7.

Implications of Redesignating Areas

Redesignation of areas from PSD Class II to non-attainment, or from PSD Class II to PSD Class III, is allowable under provisions of the Clean Air Act.

The primary advantage for such redesignation is to raise the ceiling for concentrations of the given criteria pollutant in the ambient air, thus effectively allowing greater growth of emissions-producing sources. In the case of a change from PSD Class II to non-attainment, a revised SIP must be submitted for approval to the EPA that details how reasonable further progress would be made to bring the areas into attainment. For a change from PSD Class II to Class III, enactment of legislation by the local units of government in the affected area would be required to approve the redesignation.

The possibility of such redesignations is borne out by two examples analyzed in this chapter. First, Houston presents an interesting example of attainment for SO_2, but non-attainment for allowable emissions (emissions that would be emitted under accepted permits for fuel-switching). Second, most of the counties in the two industrial belts that have high densities of emissions from industrial boilers and that are not classified as non-attainment had no monitoring data. Conceivably, once adequate monitoring data are obtained, some of these areas may prove to be in non-attainment. In either of these two examples, a decision as to the acceptability of redesignation from PSD Class II to non-attainment would have to be made. Only a very few reclassifications to non-attainment have occurred to date (12). The likelihood of the other type of redesignation--from PSD Class II to PSD Class III--is small (13). Besides the political uncertainty in the redesignation process itself, the larger increment allowed under PSD Class III could still not exceed the NAAQS, and thus any "additional" increment gained may not warrant the effort to reclassify.

A non-attainment designation may not pose the additional requirements on industry for modeling and monitoring, as would a PSD designation where baseline ambient air quality must be determined and consumption of the available increment must be tested. Further, while some sort of emission offset may be required for either a source whose emissions would violate a PSD increment or for a new source in a non-attainment area, modeling must show the PSD offset to provide a net benefit to the same area in which the new source is proposing to locate. In contrast, a non-attainment offset could receive credit for emissions reductions anywhere in the non-attainment area, depending on the particular SIP.

A number of factors weigh against redesignation, including public acceptance of non-attainment, the additional administrative procedures required for the states in revising their SIPs, and the desire of air pollution control authorities to demonstrate progress toward air quality goals. Fundamental to the efficacy of the nation's air quality programs is the continued, visible improvement in air quality, particularly when expensive control devices are being required for new sources. Increased coal use in industrial boilers may preclude such improvements. Nevertheless, it is conceivable, especially in states with powerful industrial interests, that some areas may be reclassified. On the whole, the effect of redesignation may be small. The ability of redesignations alone to accommodate increased coal use is limited.

Potential of Coal Technologies

Since offset or similar mechanisms to reduce emissions will be required for new, major source industrial boilers in non-attainment areas, and more frequently in PSD areas, the choice of the coal technology to be employed is critical. For a given amount of delivered steam, the fewer the emissions, the easier it would be to obtain emission reductions from other sources. As has been seen, only low-Btu gasification compares closely to the use of natural gas or distillate oil in terms of emissions of NO_x, TSP, and SO_2. In light of these qualifications, the coal technologies under investigation may be ranked from the standpoint of air quality. (Of course, considerations such as costs, solid waste production, and additional factors addressed in other chapters of this report need to be incorporated into any overall ranking.) The coal technologies, from the best controlled to the least controlled, are:

Best Controlled

Low-Btu gasification, Western coal

Low-Btu gasification, Eastern coal

Well Controlled

Conventional combustion + PCC + FGD, Eastern coal

Conventional combustion + FGD, Western coal*

FBC + PCC, Eastern coal

FBC, Western coal

FBC, Eastern coal

Conventional combustion + FGD, Eastern Coal

Moderate Control

Conventional combustion + PCC, Eastern coal

Conventional combustion, Western coal*

Low Control

Conventional combustion, Eastern coal

The rankings are quite sensitive to TSP control, assumed to be 84 percent efficient. The technologies tend to cluster as shown, with the differences between clusters having more importance than numerical rank. For this reason, no numerical ranks have been assigned. When technology rankings are matched with the area rankings, it becomes clear what will be the appropriate technologies for a given area. For example, it is highly unlikely that any but well controlled technologies could be sited in non-attainment areas. Also, conventional combustion with Eastern coal may only be allowable in Class II areas with substantial SO_2 increments available. More elaborate correlations are not worthwhile, since too many other factors, such as cost and space limitations, come into play.

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*90 percent SO_2 removal assumed.

One final note on the coal technologies should be added. The performance standards (NSPS) now being formulated by the EPA for new coal-fired industrial boilers, regardless of how lax or stringent, are not likely to be controlling factors on much of future coal capacity, unless present patterns of industrial concentration change. The reason for this is that, in non-attainment areas, where much of industrial boiler capacity is now located, the best available control technologies (BACT), or LAER (see Chapter 3), will be required. Insofar as the coal technologies under investigation are adequately developed, it may be assumed that only those technologies that rank "well controlled" or higher may be allowed in non-attainment areas.

CONCLUSIONS

It is highly uncertain, indeed unlikely, that a greatly increased use of solid coal in industrial boilers can be accommodated. First, industry is concentrated both regionally and within restricted geographical pockets in individual regions. Second, the use of natural gas predominates in industrial boilers. For particular regions, such as the Gulf Coast, Southeast, and Pacific Southwest, this predominance is overwhelming. Any use of coal in industrial boilers in these regions will lead to deteriorating air quality. Third, in areas now using coal, especially throughout the Great Lakes area, most of the industry is located in non-attainment areas. Paradoxically, these areas now having dirty air, attributable in large part to the combustion of coal in major sources, would stand to benefit the most from the use of "cleaner," advanced coal technologies, yet the age of existing industry and the need to clean up existing sources to bring the areas into attainment will make finding the potentials to reduce emissions for the new sources difficult. In large measure, the paradox stems from the fact that "clean air" is a finite resource, and many industries appear unwilling to "sell" their controllable emissions to other potential competitors. Furthermore, control of emissions will become increasingly difficult, and hence expensive, in the future as progress is made toward attaining the national standards for ambient air quality. To make matters worse, growth in non-point and mobile sources of pollution--autos, homes, small businesses, and the like--will continue to subtract from any allowable growth available to industry.

What are the options? Industry could relocate, an option that is expensive and that would require a much more dispersed pattern of industrial development in the future than at present. While recent indications are that much of new industrial capacity ("grass-roots") is, in fact, locating in more rural areas (10, 12), the viability of relocation is constrained by other imperatives governing siting, imperatives that are not uniform in all regions, nor that could be overlooked for many of the energy-intensive industries. Examples of such imperatives include access to transportation, raw materials, and markets, as well as the availability of skilled labor.

Barring an increased emphasis on conservation or reduced growth in demand, and acknowledging the impossibility of massively relocating industry, the fundamental fact remains that the Fuel Use Act alone appears insufficient to force the use of solid coal in industrial boilers. Indeed, the corollary question arises whether the intent of the Fuel Use Act should even be pursued for industrial boilers (the question is not raised for electric utilities). Following chapters present more information with respect to this question. Yet a few points need to be made here. First, for most of the U.S., any coal use in industrial boilers will be perceived as degrading the air quality. We have already seen, for example, that much of industry now relies on clean fuels and that most of industry is located in populous areas. Second, opinion polls continue to show strong support for environmental protection. Third, specific exemptions in the Fuel Use Act will allow many industries to by-pass conversion to coal. The conflict between the CAA and the Fuel Use Act with respect to industrial boilers could lead to an impasse that could reinforce the view that environmental and energy goals are not being effectively and jointly managed. If the use of coal is to be expanded, policies need to be sensitive to where in the energy economy the use of coal may be best accommodated without challenging air quality regulations. Apparently, industrial boilers may not be the best accommodation.

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CHAPTER 9

RESOURCES USED AND SOLID WASTES GENERATED BY COAL BURNING TECHNOLOGIES

All of the coal technologies under investigation use resources such as water, land, coal, and skilled labor, and all of the technologies generate solid wastes. The differences between technologies in terms of their resource requirements and waste discharges are a function of the primary efficiency in the process itself or of inherent differences in the configuration of the technologies and their operating parameters. This chapter discusses such differences and relates them to increased national and regional burdens for the assumed year 2000 expansion of coal use in industrial boilers.

The same technologies comprising the trajectories outlined in Chapter 6 and analyzed from the perspective of air quality in Chapters 7 and 8 are compared here. Results for the comparisons are derived from the Coal Technology Assessment's technology mix program. Data sources are detailed in Appendix B.

COMPARATIVE RESOURCE REQUIREMENTS

The comparative total resource requirements for the seven mining-to-end use combinations under investigation are presented in Figure 31. The comparisons are based on the numbers and quantities of resources required by each technology to produce an equivalent amount of steam. To facilitate comparisons, Table 32 offers percentage changes for the alternative technologies in resource requirements from those of conventional combustion of either Eastern or Western coal. As might be expected, conventional combustion requires the fewest resources, with the one exception of water, for which fluidized-bed combustion (FBC) has the lowest requirements because of its lower operating temperature (roughly two-thirds that of conventional combustion). In all categories, except raw materials, low-Btu gasification has the highest resource demands.

Mined Coal Requirements

The mined coal requirements provide an index of the relative efficiencies of the trajectories. Fluidized-bed combustion with either Eastern or Western coal is roughly equivalent to conventional combustion. This is followed in order of efficiency by physical coal cleaning, flue-gas desulfurization (FGD), FBC and FGD using cleaned coal, and finally, low-Btu gasification.

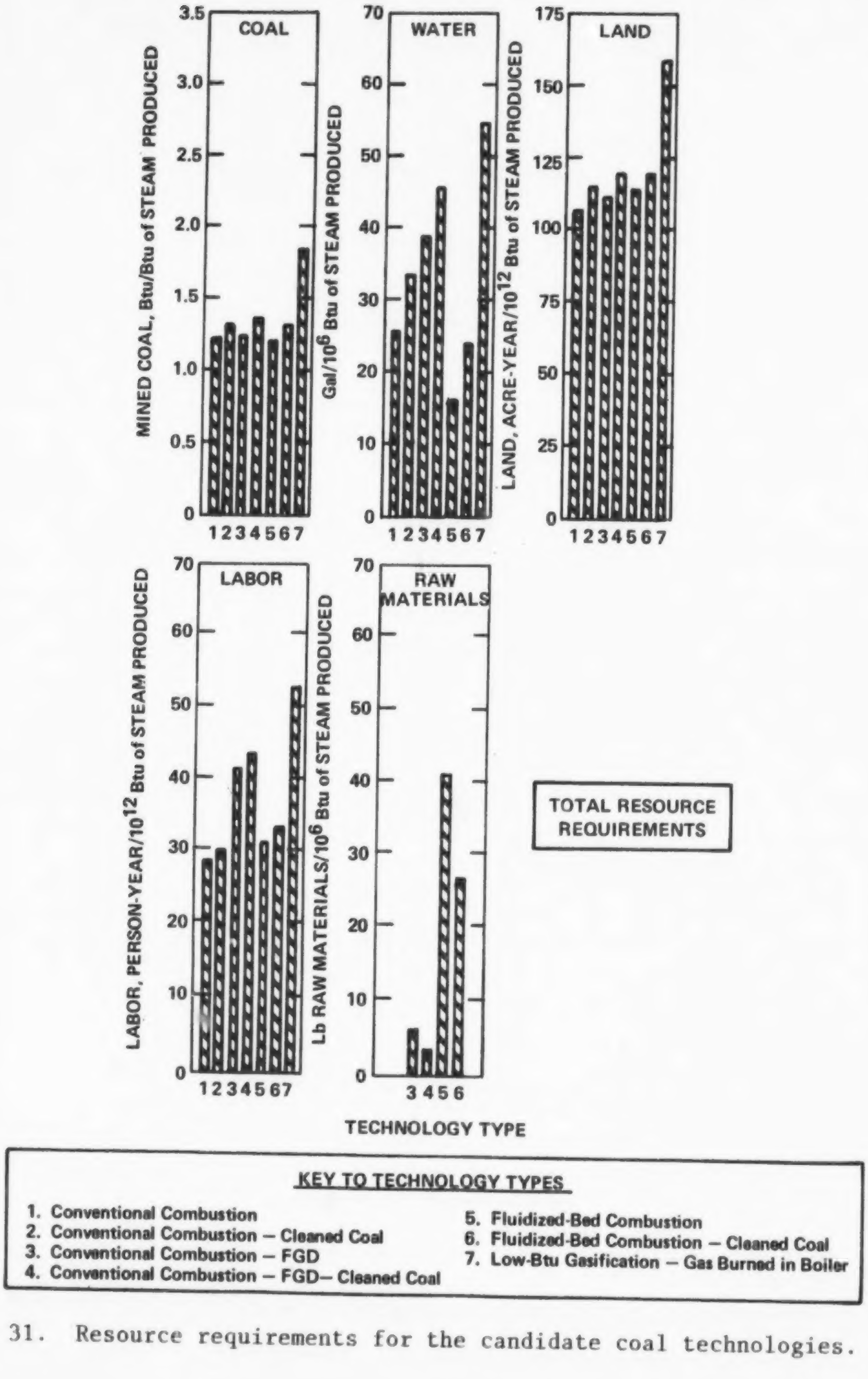

Figure 31. Resource requirements for the candidate coal technologies.

TABLE 32. RESOURCE REQUIREMENTS FOR INDUSTRIAL BOILER TECHNOLOGIES AS PERCENTAGE CHANGE FROM CONVENTIONAL COMBUSTION

Technology	Resources required[a]			
	Mined coal	Water	Land	Labor
Eastern Coal				
Conventional combustion (CC) with cleaned coal	+ 8	+ 31	+ 8	+ 7
CC with flue-gas desulfurization (FGD)	+ 2	+ 51	+ 6	+45
CC with FGD with cleaned coal	+11	+ 79	+13	+52
Fluidized-bed combustion (FBC)	0	- 37	+ 8	+ 9
FBC with cleaned coal	+ 8	- 6	+13	+16
Low-Btu gasification of coal	+52	+112	+50	+84
Western Coal				
CC with FGD	+ 2	+ 43	+ 3	+64
FBC	+ 1	- 37	0	+13
Low-Btu gasification of coal	+43	+113	+42	+96

[a] Includes resources associated with all operations from mining through steam production.

Water Requirements

The FBC trajectories, as noted above, require up to 37 percent less water than does conventional combustion. Conventional combustion of cleaned coal requires about 30 percent more water than conventional combustion alone. This difference is due to the water requirements for the coal washing step in the cleaning process. FGD requires roughly half again as much water as conventional combustion because of the water make-up in slurrying the sorbent for sulfur dioxide (SO_2) removal. Water requirements in gasification are over double that for conventional combustion, because of overall efficiency differences and because of the need to cool the raw low-Btu gas to the relatively low temperatures required in the sulfur removal process (1).*

Land Requirements

Differences in land requirements follow a similar pattern to water requirements. While land required for disposal of wastes is included in the characterizations, the figures for FGD systems are based on a 100 percent dry waste. Since waste stream of FGD sludge will be only about 50 percent solid, the difference between land requirements for FGD and conventional combustion should actually be doubled. Again, the much higher land requirements for low-Btu gasification are the result of efficiency differences (more coal must be mined) and the complexity of the on-site facility (more process modules requiring plant space). Furthermore, in situations where retrofitting is to occur for low-Btu gasification, the existing natural gas boiler would probably have to be replaced because of the newer process higher excess air requirements, lower flame temperature, and differences in gas constituents (2). The replacement would increase space requirements. (For additional discussion of space limitations, the reader is referred to Chapter 4.)

Labor Requirements

FGD and low-Btu gasification have the highest labor requirements because they require personnel to operate the scrubber or gasifier systems. These workers are in addition to the boiler operator. Because boiler operation will be slightly more complex for FBC, there is a greater labor requirement than for conventional combustion. Additional labor in physical coal cleaning arises from operation of the cleaning facility, but this impact would not be felt in labor requirements at the industrial firm itself. Indeed, the more uniform nature of physically cleaned coal may lead to lower labor requirements at the boiler site than for conventional combustion.

Raw Material Requirements

Only FGD and FBC require additional raw materials; namely, the alkaline sorbent required in sulfur removal. Raw material requirements are higher for FBC than for FGD. This difference occurs because, for the system chosen by the EA contractor as representative, a higher calcium-to-sulfur ratio for the sorbent (limestone) is required for FBC than for FGD. The calcium-to-sulfur ratio also shows up in the solid waste amounts generated, as discussed in the next section.

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*The condensate from this cooling process is felt to have low potential hazard for health effects, but a high degree of hazard for ecological effects (1). Insofar as insufficient information exists to date concerning such hazards, disposal of the waste water from the low-Btu gasification process may dictate additional treatment. No similar waste stream exists in the other technologies under investigation.

COMPARATIVE SOLID WASTE GENERATION

Solid waste generation, by type and total for the seven technologies, is compared in Figure 32. All of the technologies produce ash and tailings. For the trajectories not incorporating physical coal cleaning, the tailings category reflects what is produced at the mine site and is an indirect measure of overall efficiency. Comparison of the bar charts for ash and tailings in Figure 32 should make it obvious that the reduction in ash production (as well as sulfur) with physically cleaned coal is matched by an increase in tailings production at the physical coal cleaning plant.

As noted in the land requirements discussion above, to convert the FGD sludge figures to a more realistic 50 percent solids content, the height of the bar charts should be doubled. With this adjustment, the comparison between FGD and FBC solid waste amounts approaches equivalence, though FGD still shows a slight edge in lower waste amounts.

Table 33 converts the raw numbers for ash, tailings, and total solid waste production into percent differences from conventional combustion of Eastern or Western coal. As the notes at the bottom of the table explain, a relatively greater advantage for FGD over FBC occurs in terms of solid waste production when physically cleaned coal is used.

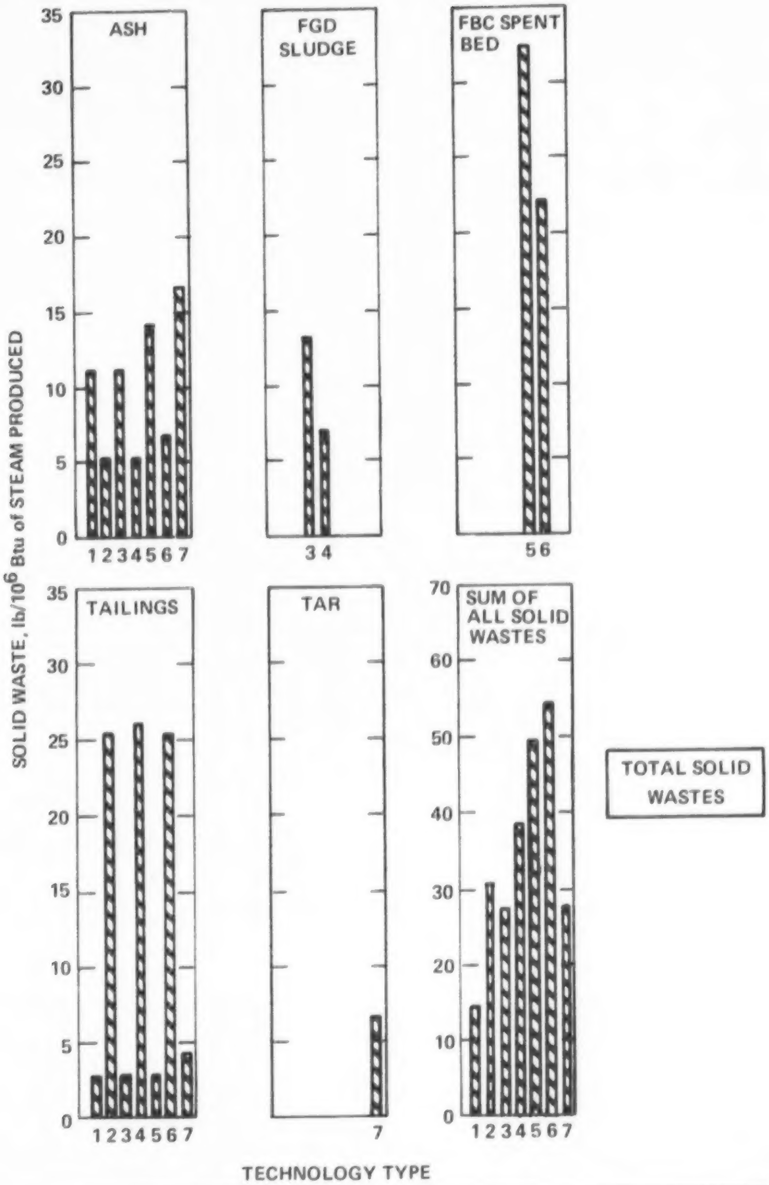
What becomes most apparent in these comparisons is that reduction of air emissions results in both greater resource requirements and greater amounts of solid wastes. The dictum that "you can't get something for nothing" prevails. Thus, when decisions are made about levels of control for air emissions, the benefits from reduced emissions must be weighed against the risk factors posed by waste disposal and the requirements for additional resources. Further discussion concerning disposal options and other environmental impacts associated with these various technologies is offered at the conclusion of this chapter.

YEAR 2000: A COMPARISON OF TECHNOLOGY MIXES

The technology mixes investigated in this section are described in Chapter 6, as well as the rationale behind the regional assignments presented. As in the previous chapters, the year 2000 coal demand in industrial boilers is assumed to be roughly 6 Q of coal input, or 4.8 Q of delivered steam.

National Resource Requirements

In Table 34 and Figure 33, the projected year-2000 resource requirements for the various technology mixes are presented. The requirements are based on all operations from mining to delivery of steam. The resources estimated to be required in industrial boilers in 1980 are also offered for comparison in Table 34. In most instances, differences between the technology mixes are not great.



KEY TO TECHNOLOGY TYPES

1. Conventional Combustion
2. Conventional Combustion – Cleaned Coal
3. Conventional Combustion – FGD
4. Conventional Combustion – FGD – Cleaned Coal
5. Fluidized-Bed Combustion
6. Fluidized-Bed Combustion – Cleaned Coal
7. Low-Btu Gasification – Gas Burned in Boiler

Figure 32. Generation of solid wastes by the candidate coal technologies.

TABLE 33. SOLID WASTES GENERATED FROM INDUSTRIAL BOILER TECHNOLOGIES AS PERCENTAGE CHANGE FROM CONVENTIONAL COMBUSTION

Technology	Solid wastes[a]		
	Ash	Tailings	Total solid waste[b]
Eastern Coal			
Conventional combustion (CC) with cleaned coal	-54	+780	+117
CC with flue-gas desulfurization (FGD)	0	+ 2	+ 93[c]
CC with FGD with cleaned coal	-54	+804	+164[c]
Fluidized-bed combustion (FBC)	+27	0	+251[d]
FBC with cleaned coal	-39	+780	+285[d]
Low-Btu gasification of coal	+48	+ 14	+ 96
Western Coal			
CC with FGD	0	0	+ 34
FBC	+51	0	+121
Low-Btu gasification of coal	+40	+ 40	+133

[a] Includes discharges and resources associated with all operations from mining through steam production.

[b] Total solid wastes include scrubber sludge and spent bed from FBC.

[c] Sludge produced by conventional combustion of cleaned coal with flue gas desulfurization is 47 percent less than that produced by CC/FGD with uncleaned coal.

[d] Spent bed produced by fluidized-bed combustion of cleaned coal is 32 percent less than that produced by FBC of uncleaned coal.

TABLE 34. YEAR 2000 TECHNOLOGY MIXES AND ASSOCIATED RESOURCE REQUIREMENTS

	Total resource required[a]					
	Coal mined					
Technology mix	10^{15} Btu/yr	10^{6} tons/yr	Water 10^{9} gal/yr	Land[b] 10^{3} acres	Labor 10^{3} persons/yr	Raw materials 10^{6} tons/yr
Industrial boilers in 1980	1.50	67.2	345	119	33.5	0.2
Reference mix	6.18	278	146	484	146	9.1
Cleaned-coal emphasis mix	6.40	289	163	500	150	5.9
FGD emphasis mix	6.24	283	172	493	172	13.1
FBC emphasis mix	6.19	280	127	493	151	35.1
Low-Btu gasification emphasis mix	7.38	336	206	570	191	9.1

[a] Includes resources associated with all operations from mining to steam production.

[b] Includes land required for waste disposal (sludge dry weight basis).

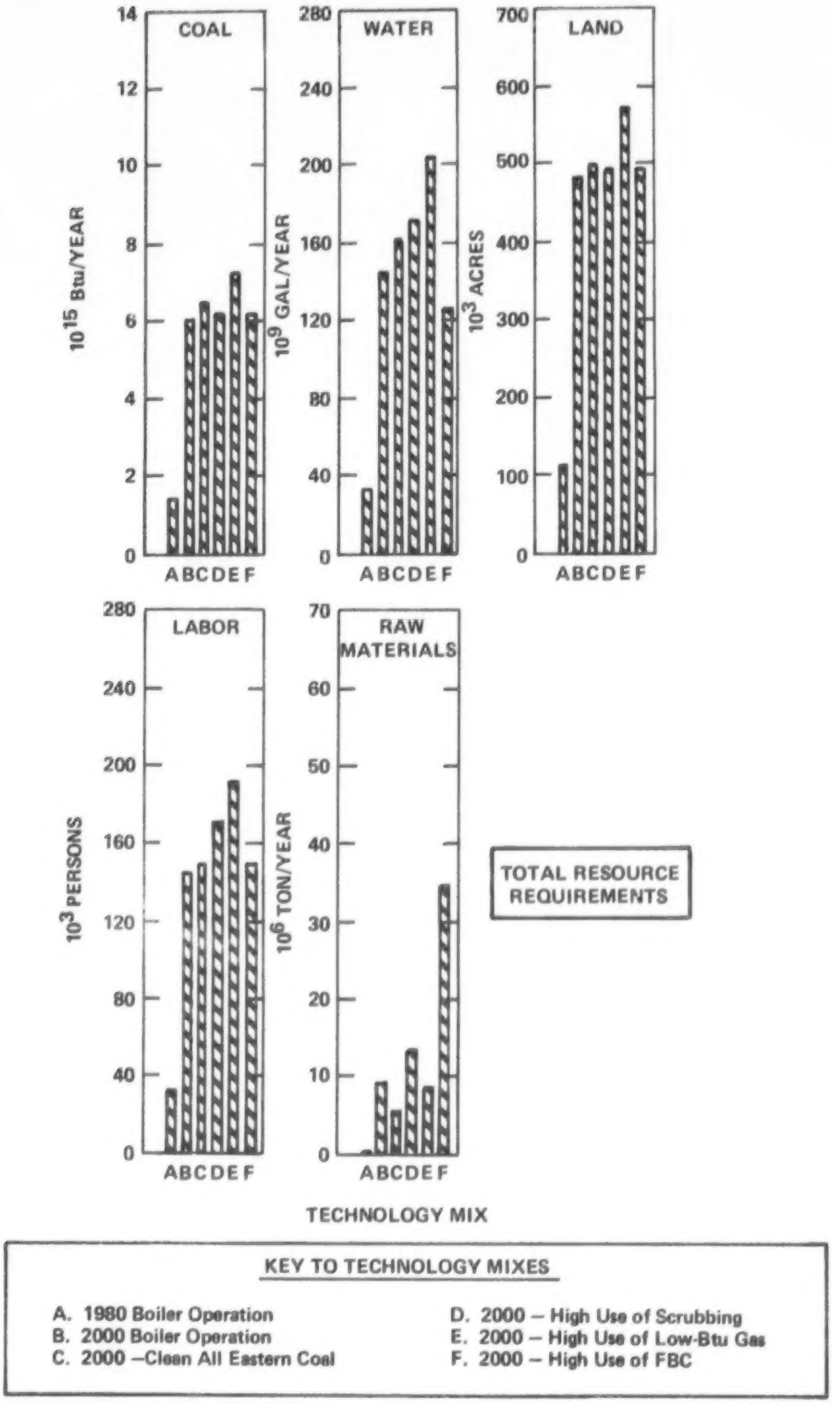


Figure 33. Resource requirements for the candidate technology mixes.

The lower efficiency for the mix emphasizing low-Btu gasification presents the most striking difference. To deliver 4.8 Q of steam, the low-Btu gas mix requires almost 20 percent more coal than does the reference mix.* As a benchmark, 1979 domestic coal use approximated 685 million short tons. Thus, the reference mix at the assumed year 2000 coal demand levels represents about a 40 percent increase in mined coal requirements for all purposes over present levels; the low-Btu gas mix represents about a 50 percent increase. These increases are not trivial and point to what will probably be the most important resource impacts resulting from an emphasis on coal use in industrial boilers.

While the 125 to 205 billion gallons of water required for the various mixes in the year 2000 appears to be an enormously large quantity, such amounts represent only about a 1 percent increase over total 1975 water requirements in manufacturing (3). Shortages and competition for water could very well occur at the local level, but nationally, this increase appears quite manageable. An emphasis on FBC would result in lower water requirements than the reference mix; an emphasis on low-Btu gasification would require 40 percent more water than the reference mix.

Land requirements could approach or exceed a half million acres by 2000 or even more if land requirement figures are increased to account for the aqueous nature of sludge. Again, however, these amounts would be required incrementally between now and the year 2000 and represent a minor fraction of the present loss of agricultural lands to development. For example, the White House Council on Environmental Quality estimates that prime agricultural land is being lost to development at a rate of about a million acres per year and that land lost to all agriculture is about three million acres per year (4). On a pro-rated basis, the land requirements for increasing coal use in industrial boilers represent less than 1 percent of the annual withdrawal of agricultural lands.

Year 2000 increases in labor requirements of 100,000 to 150,000 workers over 1980 levels represent a significant increase in employment. Many industries in the past, of course, have handled such increases with relative ease, especially when a twenty-year period of transition is considered. The greatest labor problem may come, however, not from the number of workers required, but from the types of workers required. Operation of the low-Btu gasification systems and FGD systems, and to a lesser extent the fluidized-bed combustion units, may require considerable training in chemical or process engineering. Under conditions of increased coal use, with perhaps a similar emphasis on large synthetic fuels facilities, competition for trained personnel would be great. Nonetheless, it is unlikely that labor will ever be the key constraint to increased coal use in industrial boilers.

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*Recall that the reference mix reflects the judgments of the appropriate Environmental Assessment contractor concerning market penetration for the technologies comprising the mix. See Chapter 6 and Appendix B.

Only the technology mix emphasizing fluidized-bed combustion appears to place a heavy demand on raw materials (limestone), reaching 350 million tons per year by the year 2000 at the assumed demand levels. This amount of limestone is roughly equivalent to the total demand for limestone in U.S. agriculture in 1976. Yet limestone deposits are extensive in the U.S. and worldwide, and the resource base should not pose a limitation.

In sum, resource requirements on a national basis appear to be small, with the exception of coal itself, in comparison with present demands. While these factors do not ensure that regional or local problems will not occur, it is apparent that nationally the requirements can be met. Certainly the resource requirements do not pose nearly the problem that will be created by increased coal use from the perspective of air quality or, as the concluding portions of this report indicate, the perspectives of economics or solid waste disposal.

National Solid Waste Generation

Like the resource information just presented, the information presented here on solid waste generation is based on all operations from mining to delivery of steam. The various solid wastes and the quantity of their production for the assumed coal-based steam demand in the year 2000 are graphically depicted in Figure 34, with the actual numbers shown in Table 35. For reference, Table 35 also includes 1980 waste production. The rate of steam production is assumed to increase by a factor of four between 1980 and 2000.

In the reference mix, the production of tailings increases proportionately less, 3.7, than the assumed increase in steam production, because the projected level of coal cleaning is a slightly smaller fraction of the coal used in 2000 than in 1980. All other quantities increase by more than a factor of four--that is, they increase by more than the increase in steam production, reflecting the increased solid waste production and resource requirements of the technologies emphasized or introduced in the year 2000 reference mix.

The emphasis on physical coal cleaning results in increased solid waste production over the reference mix. However, as noted previously, the increased solid waste would be generated at the cleaning plant site, usually near the mine, while solid waste generated at the steam plant--ash, FGD sludge, and FGC spent bed--would be reduced by 27, 44, and 30 percent, respectively. A further advantage of coal cleaning is that its use reduces the raw material requirements, chiefly sodium carbonate, lime, and limestone or dolomite, of the FGD and FBC technologies. The need for these materials is reduced by 35 percent in the clean all-Eastern-coal case as compared with the reference case for the year 2000.

The FGD emphasis mix shows lower waste amounts than do the other mixes, with the exception of the reference mix. Yet when the actual solids content of the waste (50 percent vs. 100 percent) is accounted for, the total waste amounts are increased to 72 million tons annually by 2000. While still

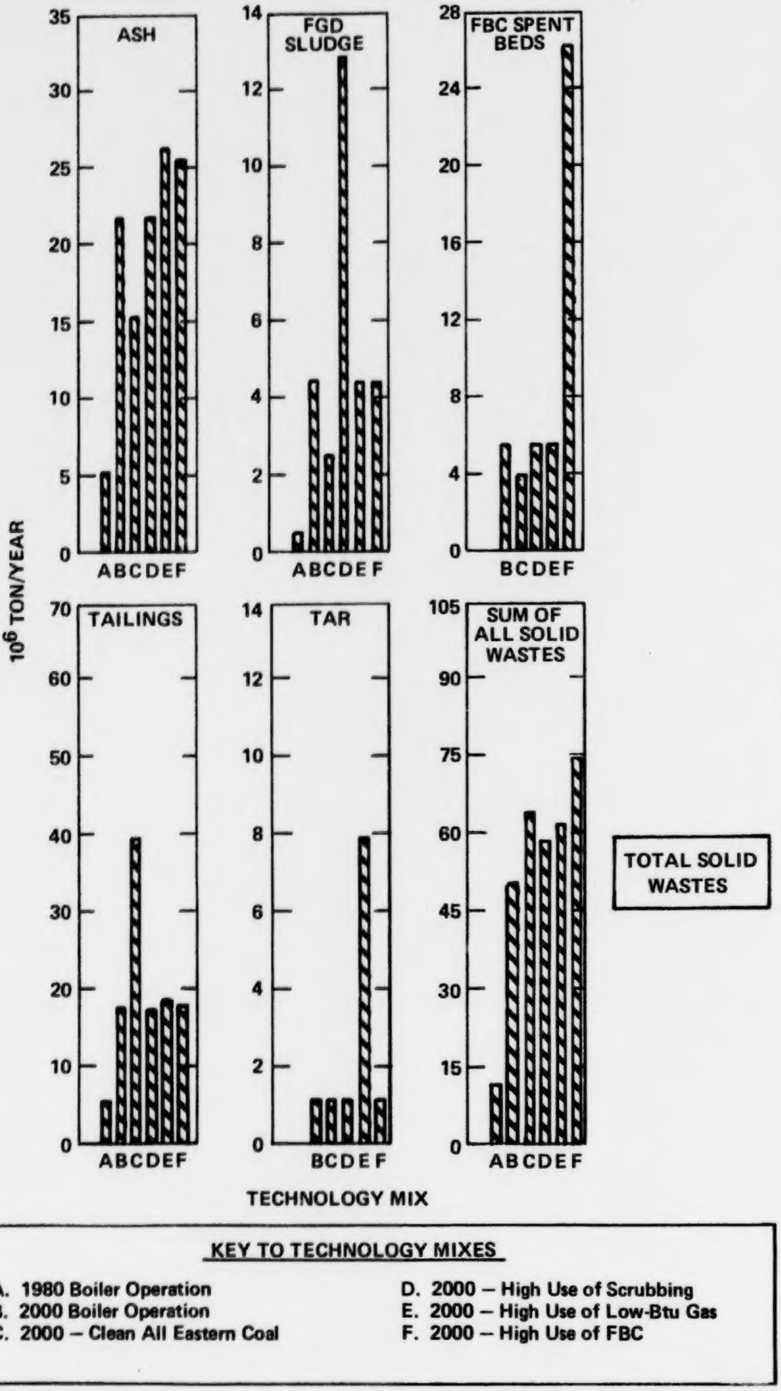

Figure 34. Generation of solid wastes by the candidate coal technology mixes.

TABLE 35. YEAR 2000 TECHNOLOGY MIXES AND ASSOCIATED SOLID WASTE GENERATION

Technology mix	Total discharges, 10^6tons/yr[a]					
	Tar	Ash	Sludge (dry wt)	Tailings	FBC spent bed	Sum of all wastes
Industrial boilers	0	5.0	0.5	5.3	0	10.8
Reference mix	1.1	21.9	4.4	17.6	5.6	50.8
Cleaned-coal emphasis	1.1	16.0	2.4	41.3	3.9	64.7
FGD emphasis mix	1.1	21.9	12.9	17.7	5.6	59.1
FBC emphasis mix	1.1	25.3	4.4	17.7	26.1	74.6
Low-Btu gasification emphasis mix	7.9	26.3	4.4	18.5	5.6	62.7

[a] Includes discharges associated with all operations from mining to steam production.

slightly lower in volume than the total wastes from the FBC mix, the need for dewatering or other treatment to make the wastes suitable for landfill, or the construction of holding ponds if the wastes are not dewatered, will increase disposal costs and may increase risks of population exposure. For the low-Btu gas mix, ash and tailing waste levels are relatively high, with tar waste levels approaching eight times the level in the other mixes.

Within the wide variation in the technology mixes assumed for the year 2000, the total solid waste production will vary from about 50 million tons to 75 million tons. While this is a significant amount, with the potential for adverse impacts in particular locales, it is small when compared nationally with solid waste from other sources. For example, as shown in Table 36:

TABLE 36. SOLID WASTES FROM NON-COAL SOURCES

Activity/year	Solid waste, 10^6 tons/yr
Metals mining (1977)[a]	1090
Phosphate rock (1974)[b]	110
Manufacturing industries (1976)[c]	157
Municipal solid waste (1976)[c]	136

[a] Reference 5 [b] Reference 6 [c] Reference 7

However, viewed from the perspective of solid waste amounts now handled by industry, year 2000 wastes could pose major economic, logistic, and, perhaps, regulatory burdens. Recent levels of solid waste generated by industry are shown in Table 37. Note that two industries, primary metals and inorganic chemicals, account for over 90 percent of all industrial wastes. Much of the burden of solid waste management will fall on industries that are now energy-intensive, such as petroleum refining, but that do not have a history of waste management. Industries like primary metals and inorganic chemicals, which have had to deal with waste problems in the past, should be able to cope reasonably well. Nevertheless, wastes generated at the facility sites (thus excluding tailings) for the various year 2000 technology mixes would range from 23 to 57 million tons, or a 15 to 35 percent increase over present manufacturing waste levels.

Looking at solid waste burdens from the perspective of percentage increases alone, however, has two fundamental shortcomings. First, the United States already has a severe waste disposal problem in all waste categories--

TABLE 37. U.S. INDUSTRIAL WASTE GENERATION, 1974 BASIS[a]

Industry category	Total dry weight, 10^6 tons
1. Batteries	0.00
2. Inorganic chemicals	44.00
3. Organic chemicals, pesticides, explosives	2.42
4. Electroplating	1.00
5. Paints	0.41
6. Petroleum refining	0.69
7. Pharmaceuticals	0.27
8. Primary metals	110.38
9. Textile dyeing and finishing	0.34
10. Rubber and plastics	2.21
11. Leather tanning and finishing	0.07
12. Special machinery	0.34
13. Electronic components	0.04
14. Waste oil re-refining	0.06
Total	162.22

[a] Reference 8

municipal, industrial, hazardous. Because of this present problem, the incremental burden assumes great importance. Second, much of industry is now located in urban areas. Not only does this increase the populations-at-risk, but it adds to the already taxing burden of municipal waste disposal, protection of surface and groundwater quality, and maintenance of an aesthetic urban environment.

While the total amounts of solid wastes are relatively insensitive to the technology mix assumed, the character of the wastes generated is not. The wastes and range of amounts for the year 2000 mixes are shown below.

Type of Waste	Amount (10^6 tons)
Tar	1.06 to 7.92
Sludge	2.44 to 12.9
FBC spent bed	3.92 to 5.57
Ash	16.0 to 26.3
Tailings	17.6 to 41.3

Tars are produced only by low-Btu gasification. Tars and oils from coal are known to contain toxic and mutagenic materials (9). They must be handled with extreme care and, ultimately, destroyed. While it is anticipated that tars and oil from gasification could be burned in conventional boilers, probably in combination with other fuels, the amounts of tars produced, especially with high use of low-Btu gasification, are sufficiently large that careful planning and monitoring will be required to avoid adverse consequences from handling these materials.

The sludge from FGD and spent bed from FBC are composed of lime or limestone that combine with sulfur from the fuel and with coal ash. Both types of waste have been widely studied from the standpoint of potential disposal problems. While wide use of either process by utility or industrial boilers would represent a significant addition to the national solid waste burden and might in some locations present local problems, the amounts contributed by industrial boilers could be viewed as modest.

Coal ash from combustion and tailings from physical coal cleaning that would be produced by industrial boilers in the year 2000 represent a modest increase in the amounts of such waste that have been generated over the years; for example, coal ash from utility boilers is currently about 45 to 50 million tons per year, and coal cleaning tailings totalled 98 million tons in 1974. Methods for proper disposal of ash and tailings are currently available, and adverse environmental impacts from disposal of fly-ash and tailings associated with future industrial boiler operation should not occur if adequate management is employed. The fact that some industrial plant locations have limited sites for disposal highlights the value of physical coal cleaning in reducing the solid wastes generated at the plant site.

Regional Solid Waste Burdens

To estimate the regional distribution of increased solid waste burdens from the assumed year 2000 industrial boiler coal demand, we used a procedure similar to the regional disaggregations in the previous chapters on air quality. Figure 35 presents the distribution of wastes from physical coal cleaning and from the boiler technologies, based on the reference mix. (The figure does not account for wastes resulting from mining the coal.)

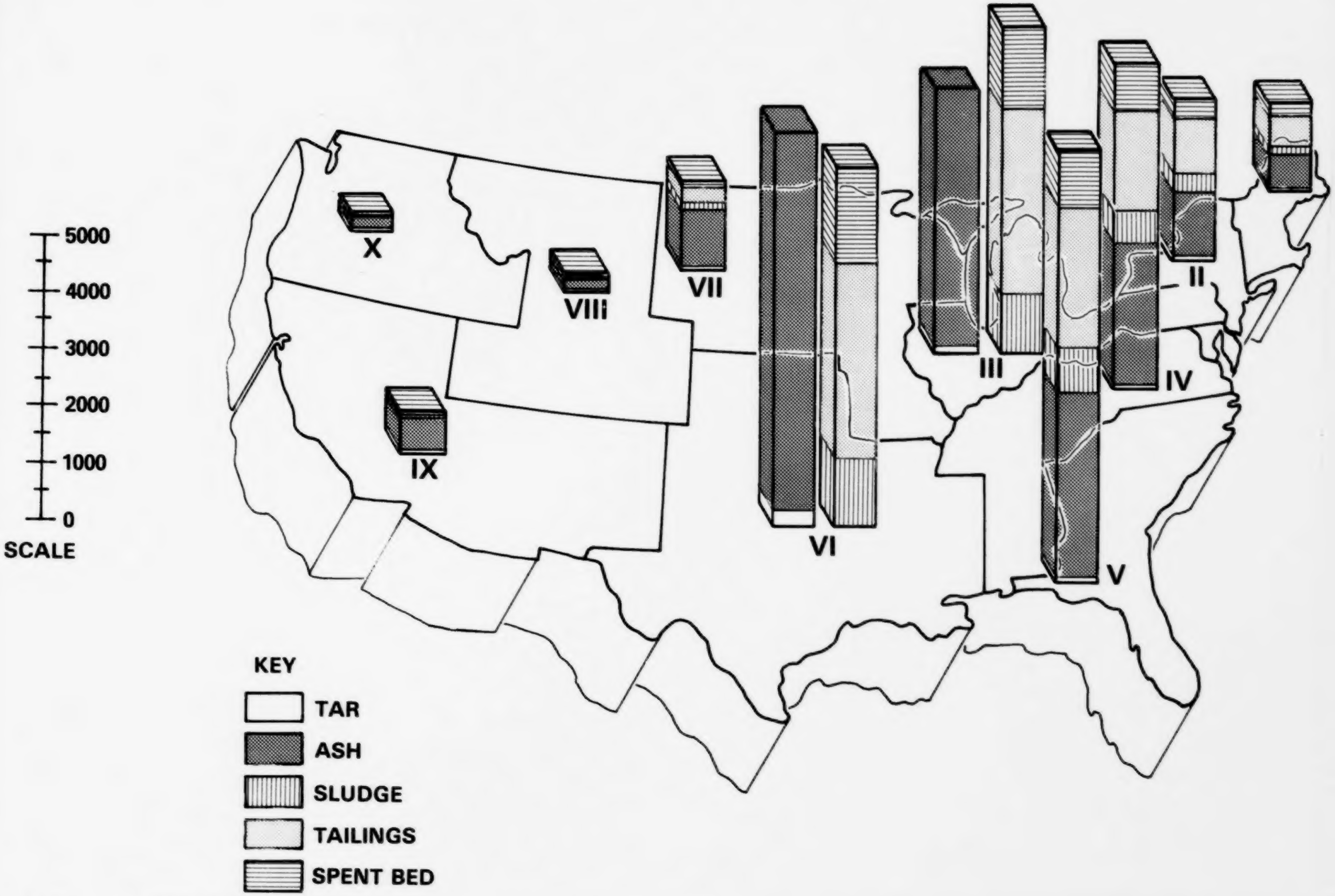

Figure 35. Year 2000 regional solid waste burdens.

The Gulf Coast (VI) region, followed by the Great Lakes (III) region, shows the largest burden. Combined, these two regions account for over 50 percent of the total solid waste generated, largely because they are highly industrialized. Under any scenario of increased coal use in industry, the Gulf Coast would bear by far the greatest increase in solid waste burdens because of the predominance of natural gas use in that region.

Wastes produced in the three westernmost regions--the Rocky Mountain (VIII), Pacific Southwest (IX), and Pacific Northwest (X)--account for substantially less than 5 percent of the total solid wastes projected. In addition, when the wastes in the New England (I) region are added to those from the three westernmost regions, the total share of the four regions is only slightly above 5 percent. Thus, the remaining regions, that is, the central portion of the U.S., would bear the burden of managing about 95 percent of the solid wastes.

Naturally, these assumptions must be understood as relatively arbitrary assignments. First, total coal demand may not approach the levels assumed (there is also the possibility, though less likely, that demand could be greater). Second, regional development patterns may vary. Third, there could be a greater reliance on Western coal in the future. Fourth, the mix of technologies may not follow the pattern of the reference mix. However, as Table 38 indicates, all of the emphasis mixes would generate higher volumes of waste than the reference mix.

TABLE 38. PERCENTAGE CHANGE IN SOLID WASTE PRODUCTION FROM EMPHASIS MIXES OVER NATIONAL REFERENCE MIX

Waste	Clean coal emphasis (% change)	FGD emphasis (% change)	Low-Btu gas emphasis (% change)	FBC emphasis (% change)
Tar	0	0	+647	0
Ash	-27	0	+ 20	+16
Sludge (dry weight)	-44	+194	0	0
Tailings	+135	0	+ 5	0
FBC spend bed	-30	0	0	+369
Total	+28	+17	+ 24	+48

These caveats aside, a number of conclusions can be drawn concerning the implications for increased coal use in industrial boilers. First, if good air quality is to be maintained, larger volumes of solid waste will be produced than in the past. Second, we can assume from historical patterns of industrial development that the increases will be felt mostly in the central portions of the U.S. It is these very areas that already have the greatest waste disposal problems. And third, those areas now relying heavily on natural gas, such as the Gulf Coast, would suffer the greatest increases in waste levels. The patterns shown in Figure 35 therefore capture the relative solid waste increases at the regional level.

But how serious would such increases be? Unfortunately, little is known concerning the long-term fate of wastes derived from coal-based energy technologies. What can be said, however, given our present knowledge, is the topic of the next section.

FACTORS OF RISK ASSOCIATED WITH SOLID WASTES FROM COAL TECHNOLOGIES

The risks posed from solid wastes are a function of the type of waste, the location of the disposal site, and the long-term integrity of the disposal site for sequestering constituents of concern. Because little is known concerning tars (aside from their potential carcinogenicity or mutagenicity), because ash has been handled adequately in the past, and because tailings from physical coal cleaning would be disposed of at the site of the cleaning facility (generally removed from population centers), the focus of this section will be mostly on FGD wastes. More is known concerning the chemical constituents and disposal options for FGD wastes than is known about FBC spent bed wastes. Where appropriate, however, parallels and contrasts to FBC wastes are drawn. Much of the material in this section is based on an internal Coal Technology Assessment working paper (10) that discusses the state-of-the-knowledge of FGD sludge and disposal.

Wastes and Their Impacts

Air--

Fugitive emissions are possibly the only source of adverse air impacts from FGD system wastes. If a reheater is applied to the flue gas exiting the scrubber, visible plumes and localized acid mist can be decreased.

In sludge, depending on the degree of oxidation in the FGD system, bound particles smaller than 74 microns (which, if freed, can be carried through the air further than 100 feet) can range from 60 to 95 percent of the total number of particles present. Particles in the respirable size range (smaller than 2 to 3 microns) are usually on the order of 5 percent or less. Potentially, in the drying of the sludge (considered here to be a week or more without wetting), this could cause problems, especially from wind erosion during landfill or surface mine disposal operations. Periodic spraying of waste piles with fine water mists or establishment of buffer zones up to one kilometer around disposal sites may be required for operations with high fugitive emissions.

These control options, then, may increase land or water requirements for disposal.

Finally, and perhaps most importantly, recent evidence suggests that the emission of very fine sulfate particles may increase when scrubbing is applied. Sulfates are coming under increased scrutiny because they are suspected precursors to acid precipitation.

Water--

Potentially harmful compounds from sludges may enter water supplies through surface or groundwater. Routes to surface water include rainwater displacement from holding ponds, rainwater runoff (especially treated sludge in landfills), and direct runoff. The latter can occur through spillage or through the breaking of holding dams. Routes to groundwater include seepage through pond, landfill, or mine disposal sites (particularly for tailings), or runoff to adjacent land with eventual seepage.

The types of pollutants in sludge and their rates of entry into the environment defy easy characterization since the source of coal, the scrubber system used, the disposal option chosen, and the sludge treatment method are all key variables. A few general relationships may be offered, however.

In pond disposal, the permeability of untreated sludge is on the order of 10^{-4} to 10^{-5} cm/sec. Chemical treatment of sludge can decrease permeability by as much as several orders of magnitude, though occasionally treatment may result in greater permeability. Permeability is an indirect measure of unbound pollutant migration through the sludge. In general, Eastern coal sludges demonstrate less permeability than Western coal sludges.

The extent to which permeability is a parameter of concern is largely a function of the integrity of pond linings in preventing further leaching. Pond linings include soil such as clay, impermeable substrata such as granite, or plastic sheeting or other coatings. Compacted earth or clay lining is suitable for impoundments in all soil types except sands, gravels, or other porous soils. The lifetime of plastic liners is on the order of 30 years, and the ponds themselves are only constructed to hold the sludge projected to be produced during the lifetime of a particular facility. What occurs when the liners break down or when the ponds are eventually filled has not been addressed. Total dissolved solids and trace elements in the sludge are of particular concern.

Secondary impacts on water quality from scrubber sludge could be quite marked, as the total dissolved solids (TDS) may exceed 70,000 ppm in the waste liquor from scrubbed Eastern coal, and aluminum, arsenic, barium, beryllium, boron, cadmium, cobalt, copper, chromium, fluorine, iron, lead, magnesium, manganese, mercury, molybdenum, nickel, selenium, silver, vanadium, and zinc (among others) have been found in sludge elutriates. In fact, the National Interim Proposed Drinking Water Standards (NIPDWS) have been exceeded for many of these trace elements, frequently by a factor of ten.

Boron, calcium, cadmium, manganese, mercury, selenium, and TDS frequently exceed the NIPDWS by factors of ten, and arsenic and silver levels are also sometimes higher than the standard. While no standards exist for molybdenum, chlorides, and fluorides, these components may also be of concern. Sulfite-rich FGD wastes also appear to dissolve quickly enough to exert considerable oxygen demand on receiving waters.

At the present time, the presence, absence, levels, or types of polycyclic organic material in sludge are unknown. No biological testing has been performed on leachates or sludge liquors, so that potential health effects from these complex wastes are unknown. However, current efforts are underway within EPA to provide this information.

Land--

Impacts on terrestrial wildlife and vegetation may also be important factors, especially as additional enabling legislation (and hence, regulations) may be brought to bear on disposal options. The use of active disposal ponds by water birds, particularly if there are sources of food (such as farmlands) nearby, compounds some of the concerns noted above for impounding untreated sludge. For vegetation, leachates may be a source of impacts from landfills, surface mines, and impoundments. In addition to the potentially harmful compounds previously noted, high concentrations of sodium chloride and other salts in leachates and rainwater runoff from holding ponds can exert osmotic stresses on plants. Reclamation of landfills and impoundments is also an open question. For animal wildlife, loss of habitat will be an additional impact.

Finally, the aesthetic impacts of land disposal, in particular as more non-regenerative FGD systems are applied, could have local importance.

Methods for Disposal

The choice of disposal method affects land requirements for disposal, the effectiveness of sequestering potential pollutants from the environment, and cost. These impacts in turn are influenced by the FGD system utilized, the coal feed, and specific characteristics of the disposal site. Ultimately, the impacts should be traded off to alternative sulfur control strategies, such as fluidized-bed combustion or coal cleaning. In the simplest terms, pond disposal of untreated wastes poses the most potential harm to the environment, and chemical treatment for landfill or mine disposal poses the least harm. However, costs, land availability, distance from waste disposal site, soil characteristics in the disposal area, proximity of the site to sources of drinking water, and possible regulations that may be promulgated for FGD waste disposal and handling, complicate decision-making.

The presence or absence of flyash in scrubber wastes influences the chemical and physical nature of the waste. The presence of flyash in lime and limestone scrubbing causes a minor increase in waste density over ash-free conditions, though no such definitive trends have been shown for double-alkali systems. However, removal of flyash ahead of the scrubber does not significantly reduce the concentration of most trace metals in sludge liquors and leachates. One explanation for this may be that many of the trace elements are found on the finest flyash particles not captured by electroststic precipitators (ESPs). An important question is whether scrubbing downstream from flyash removal decreases overall fine particle emissions. Recent reports on the mutagenicity of fine flyash indicate that this is an important area for investigation.

Increased dewatering decreases the land required for disposal and improves waste handling. In addition, dewatering does not decrease just water, but waste liquor that can contain relatively high concentrations of trace elements, TDS, chlorides, and other undesirable entities. In situations where wastes are pumped to disposal, however, dewatering may need to be limited until waste placement to ensure that it can be pumped.

Settling, draining, filtering, and centrifugation, in increasing order of dewatering ability, are the techniques available. Wastes with the coarsest particle size distributions (limestone systems) have the best overall dewatering characteristics. Lime, and especially double-alkali, systems produce finer particles and thus have the poorest dewatering characteristics.

Limiting the access of pollutants to the environment can be achieved by decreasing waste permeability, increasing the binding of major soluble species in the waste matrix, and managing the waste to prevent seepage and runoff. Chemical treatment can assist all of these measures.

Leachate concentrations of major species (especially sodium, chlorides, and sulfates) are 25 to 50 percent less in treated wastes than in untreated wastes. However, trace element concentrations from treated ponds show trends similar to untreated ponds. In particular, arsenic, cadmium, lead, zinc, and selenium have been found to persist at levels significantly above background for treated and untreated wastes, and boron appears to increase when wastes are treated to levels approaching that of input liquor.

In terms of mass loading of pollutants to the subsoil, an untreated site that is continuously covered with water discharges several orders of magnitude more pollutants than a site where waste is treated and managed to shed water, and about one order of magnitude more pollutants if the waste is untreated and only rainfall is allowed to enter the site. A summary of the major options for industrial solid waste disposal is presented below.

Ponding--

Untreated FGD waste dewatered by settling or draining must be ponded (with the possible exception of direct discharge of the aqueous stream from the sodium carbonate system, which is not investigated in this report). Native or imported clay linings, or plastic liners or coatings may be used to inhibit leachates from entering receiving waters. Eventual reclamability of disposal ponds is very questionable. Pond liners may break down over periods of tens of years. Also, poor or simply undeveloped construction practices may also allow leakage through improperly lined ponds, which is extremely difficult to monitor after impoundments are constructed and filling has begun.

Proximity to streams or sole-source aquifers should certainly preclude impoundment. Areas of high rainfall will mean constant hydraulic head on the pond, a condition that should probably be avoided. Impoundments may be adequate in the western U.S., where rainfall is low, discharge to aquifers is slow, and the groundwaters have a high buffering capacity.

Landfill--

Highly dewatered (filter/centrifuge) or chemically treated FGD wastes may be landfilled. Advantages over ponding include lower land requirements, good potential for land reclamability, management to prevent runoff, and elimination of hydraulic head to decrease mass pollutant loadings. If chemically treated, leaching or major constituents can be minimized, though trace elements may still be leached. Because of these trace elements, siting of landfill disposal sites near aquifers or free-flowing streams should be avoided.

In certain cases, arrangements with municipal landfills may be made. However, the additional demands placed on municipal treatment could embroil the industries in political battles with other community users who do not wish to subsidize the costs (usually high for landfill options) of industrial treatment.

Requirements on Land

Chapter 4 outlines the qualitative problems faced by industry in securing land and space for a number of energy-related purposes, including waste disposal. In this section, the quantity of land required for waste disposal for the facility size chosen as "typical" in our analysis (100,000 lb/hr of steam) is presented. The system selected is equipped with a double-alkali FGD scrubber; because an appropriate account is made for the aqueous nature of the FGD sludge, the figures presented should also be roughly applicable to the land requirements in spent bed disposal from a similarly sized fluidized-bed combustion boiler. In addition, some comparisons are made to other FGD units suitable for industrial application.

Projection of disposal land requirements are affected by numerous variables. Factors such as the sorbent-to-SO_2 ratio and the sorbent utilization rate influence the amount of waste generated. Land requirements for disposal, in turn, are influenced by the same waste generation rates (expressed in terms of 100 percent solids), the percent solids content of the wet waste, and the wet bulk density of the waste.

For example, a 5 percent or a 10 percent difference in wet bulk density translates into 5 or 10 percent differences in land requirements, all else being equal. Similarly, a 20 percent difference in percent solids can translate to a 20 percent difference in land requirements. Generally, differences in wet bulk density are in the 5 to 10 percent range, as reported in the literature (see further, reference 10), with reported solids contents varying by 10 to 20 percent. Thus, for example, at a given load factor, a 5 percent difference in waste generation rate, a 20 percent difference in solids content, and a 5 percent difference in bulk density, can mean as much as a 30 percent difference in total land requirements. These differences all fall within the range of reported values.

These ranges point out the difficulties in drawing distinctions between different FGD systems on the basis of land requirements for disposal, and indicate the confidence that can be placed in regional or national projections of land requirements, based on theoretical process variables. Decisions concerning particular FGD systems will necessarily require consideration of case-specific factors. Moreover, generally, differences in land requirements of up to 25 percent or so should be interpreted as insignificant.

Table 39 outlines the assumptions used in this analysis to calculate land requirements for FGD waste disposal. These assumptions have been translated into land requirements for disposal for representative facilities in industry, as shown in Table 40.

TABLE 39. KEY ASSUMPTIONS FOR CALCULATING LAND REQUIREMENTS FOR DISPOSAL OF FGD WASTES [a]

	Without flyash		With flyash	
Process	Solids contents %	Bulk density (lb/ft^3)[b]	Solids contents %	Bulk density (lb/ft^3)[b]
Lime				
Settled	40	84	40	93
Centrifuge/filter	55	94	60	95
Chemical treatment	-	-	65	113
Limestone				
Settled	45	91	45	100
Centrifuge/filter	75	110	70	110
Forced oxidation	80	112	80	113
Chemical treatment	-	-	75	113
Double-Alkali				
Settled	40	84	40	93
Centrifuge/filter	60	100	65	101
Chemical treatment	-	-	65	108

[a] While differences in bulk density have been noted between Eastern and Western coals, insufficient data exist to assign values on the basis of coal type.

[b] lb/ft^3 = 0.0160256 g/cc.

TABLE 40. LAND REQUIREMENTS FOR FGD WASTE DISPOSAL FOR A SINGLE INDUSTRIAL FACILITY[a]

			Waste volumes generated Tons/hr (100% solids)		Acres required over 30 years[b]	
Process	Coal type	% S removed	Without flyash	With flyash	Without flyash	With flyash
Lime						
Settled	Eastern	90	0.68	1.24	3.7	5.9
	Western	75	0.12	0.47	0.7	2.2
Centrifuge/ filter	Eastern	90	0.68	1.24	2.4	3.9
	Western	75	0.12	0.47	0.4	1.5
Limestone						
Settled	Eastern	90	0.90	1.46	4.0	5.7
	Western	75	0.16	0.51	0.7	2.0
Centrifuge/ filter	Eastern	90	0.90	1.46	2.1	3.4
	Western	75	0.16	0.51	0.7	1.2
Forced oxidation	Eastern	90	0.09	1.46	1.8	2.9
	Western	75	0.16	0.51	0.3	1.0
Chemical treatment	Eastern	90	0.90	1.46	-	3.0
	Western	75	0.16	0.51	-	1.0
Double-alkali						
Settled	Eastern	90	0.76	1.32	4.1	6.3
	Western	75	0.14	0.49	0.8	2.3
Centrifuge/ filter	Eastern	90	0.76	1.32	2.3	3.6
	Western	75	0.14	0.49	0.4	1.4
Chemical treatment	Eastern	90	0.76	1.32	-	3.6
	Western	75	0.14	0.49	-	1.4
Sodium carbonate[c]	Eastern	90	0.61	1.17	-	-
	Western	75	0.11	0.46	-	-

[a] 100,000 lbs steam/hr, 45% average load factor.

[b] 30 feet disposal depth assumed.

[c] The sodium carbonate system produces an aqueous waste stream with only 5 percent solids content. Thus land requirements have not been calculated. In general, this system would require water treatment, then discharge to receiving water.

In all cases, the double-alkali system shows the greatest land requirements, with limestone having the least requirements for sludge plus ash disposal, and lime the least land requirements for sludge alone. However, none of the differences is significant. When the sludge is dewatered (by centrifuge or filter) for Eastern or Western coals, with or without flyash, land requirements for disposal decrease 35 to 45 percent over the settled case. With chemical treatment for all cases, decreases in land requirements over the settled case fall into the range of 45 to 50 percent. All of these decreases are significant. Chemical treatment leads to lower land requirements than extensive dewatering, a decrease of 1 to 25 percent.

For Eastern coals, all cases demonstrate a 50 to 70 percent increase in land required for sludge plus ash disposal over disposal of sludge alone. For Western coals, this same increase is on the order of 300 to 360 percent. While these figures appear to favor sludge disposal alone, it would still be necessary to dispose of the flyash. Though flyash is collected in a dry state, water is frequently added for dust suppression and for slurrying (piping) to the disposal area. In these cases, land requirements for disposal of sludge and flyash alone will not be appreciably less than sludge plus flyash disposal. In addition, the duplication of handling and transport equipment in this case would add to capital costs. However, disposal of dry flyash and wet sludge separately should offer some advantages in terms of land requirements, and possibly in terms of risk--the possible synergisms between flyash and sludge when disposed together have not been adequately addressed.

For all systems and treatments, land requirements for Eastern coal are about six times greater than for Western coal for disposing sludge alone, and about two-and-one-half to three times greater for disposing sludge plus flyash.

The method assumed for chemical treatment requires admixing flyash or collecting it concurrently.

One further consideration must be introduced. The Resource Conservation and Recovery Act (RCRA) of 1976 and subsequent interpretation by EPA require that disposed wastes must be 5 feet above the historical high water table, with an additional soil layer of 5 to 10 feet on top of that, depending on disposal site design and local climate. If an impermeable artificial liner is used, the additional soil layer need only be a foot thick (11). Thus, these considerations and other site-specific factors may limit disposal depths (therefore increasing acreage required at the disposal site) or the selection of some disposal sites.

The implication of this analysis of land requirements in sludge disposal is that the total land requirements for the various mixes, as well as the different waste generation rates, are subject to fairly wide estimation, perhaps up to 35 percent for any particular case. However, the total amounts are not nearly so important as where the waste disposal sites may be located, as is discussed in the next section.

Proximity to Populations and Drinking Water Supplies

Two-thirds of major U.S. industrial capacity is located in municipalities. Because of the relatively high costs of transporting solid wastes, estimated to increase annual costs in the range of 10 to 130 percent of total disposal costs for each 10 miles transported (10), economics dictate that disposal sites must be located relatively close to the boiler site. Thus, for the assumed year 2000 solid wastes from the boilers, two-thirds, or roughly 16 to 38 million tons depending on the mix, will require disposal near cities or urban areas. Such amounts translate into an increase of 10 to 30 percent over the present amounts of disposed municipal wastes. Considering that the solid wastes from the industrial boilers would also be concentrated regionally, the increases to the central portions of the U.S. would be even more severe.

Under these conditions, disposed waste could therefore be located close to a significant portion of the nation's population. Not only does this dictate that sound judgment must be exercised in disposal practices, but also that candidate disposal sites must compete with alternative development or land use plans. No studies have investigated how higher land prices may affect disposal costs or the willingness of industries to transport wastes over longer distances. Certainly, however, much additional research on quantifying the risk factors of adjacent populations should be performed.

Even if wastes are disposed at a distance from population centers, care must also be taken to keep waste leachates or runoff from drinking supplies. Most industries are located in the "wet regions" of the nation, regions where groundwater and surface contamination are most likely (8). As pointed out elsewhere in this report, the central and eastern regions of the U.S. are where industry predominates. Such regions also have maximum levels of rainfall and low evaporation rates. These factors combine to enhance the likelihood of waste leaching or runoff. When drinking water aquifers are also mapped onto rainfall, evaporation, and industrial concentration, the possibility of contamination is revealed to be even greater. For example, a recent EPA report concerning hazardous waste disposal drew three conclusions: (1) most areas of high industrial concentration are underlain by principal aquifers; (2) aquifers supplying large drinking supplies occur principally in the drier western U.S., where fewer wastes are disposed but where contamination would result in severe environmental and economic impact; and (3) while many aquifers in highly industrialized areas are not currently relied on for drinking supplies, the risk of groundwater contamination should be viewed with concern (8).

In another study (12) of the relationship between water supplies, urban areas, and industrial concentration in the state of Illinois, Santini found the availability of water to be a key determinant of industrial location. Furthermore, those industries with the greatest air pollution (and hence, the most energy-intensive and likely candidates for the coal technologies under investigation) are also large employers and thus tend to choose urban sites for their facilities. These factors combine to place urban populations at risk to both air and water pollution. The irony may be that policies to decrease air pollution may increase water pollution, particularly if solid waste disposal sites are improperly managed or inadequately regulated. Given the urban nature of much of industry, it is apparent that greater attention should be paid to the interaction of air, land, and water in environmental control policies.

Solid wastes from coal-fired facilities do not pose health risks of the magnitude ascribed to hazardous waste sites, so frequently in the news of late. However, as long as great uncertainty exists about the long-term viability of coal-based solid waste disposal sites, their risks to nearby populations should not be viewed as an idle concern. Many of these issues are now being deliberated in the rulemaking proposals for the Resource Conservation and Recovery Act, discussed in Chapter 3.

Additional Risk Factors from the Candidate Technologies

Before proceeding to the economics of the various candidate technologies, a few words should be offered on some of the other risk factors associated with them. Since many of the technologies are not presently in commercial development, quantitative comparisons are impossible. Rather, the factors mentioned point the way to additional topics that deserve attention.

FBC--

FBC spent bed shares many characteristics with FGD sludge, with two important exceptions. First, spent bed is generated dry and therefore does not require dewatering. Second, FGD sludge can contain large amounts of sulfite ion (SO_3^-), whereas spent bed does not. Sulfite is important because it exerts a chemical oxygen demand on receiving waters. Because of the alkalinity of the sorbent, both FGD and FBC wastes have high pH.

Concern with FBC spent bed arises from heat release in the wastes when they are exposed to water. The heat release results from lime hydration. Waste disposal and handling may therefore require special techniques.

Low-Btu Gasification--

It is quite likely that tars produced by gasifiers may be classified as "hazardous" under RCRA, necessitating more elaborate and expensive disposal procedures. Ash from gasifiers may also contain higher amounts of trace elements or other compounds than the ash from the other candidates. If the ash is classified as hazardous, waste ash disposal from low-Btu gas may be placed at a substantial disadvantage to ash disposal from the other candidates. Other differences in air emissions are noted in Chapter 7.

Physical Coal Cleaning--

Physical coal cleaning offers one distinct advantage and one distinct disadvantage to the other candidate technologies. Insofar as disposal space may be constrained at the boiler site, physical coal cleaning can help reduce on-site waste demands. With uncontrolled conventional combustion, a degree of SO_2 control is achieved as well as a reduction of over 50 percent in the ash requiring disposal (with Eastern coal). When combined with FGD or FBC, coal cleaning can reduce spent bed waste by approximately 30 percent, sludge by almost 50 percent, and ash by over 50 percent. Additional improvements in lessened trace element emissions, especially mercury, may also occur.

The disadvantage is that total waste amounts are increased, though disposed at the mine site. The tailing waste is generated in an aqueous state, thus presenting disposal problems not unlike sludge. Further, "fines," or very small particles of crushed coal, are produced, which can infiltrate and contaminate water, especially through runoff. Though at first glance, particularly with the urban character of industry, disposing wastes at the mine site appears to be a superior strategy, the trade-offs are not simple. For example, the number of coal waste dumps is now estimated at about 5000, and these numbers would grow with a heavier reliance on coal cleaning. Half of these sites are now estimated to pose some level of health, environmental, or safety problem (13).

The conclusion to be drawn from the foregoing discussion is that the undesirable entities in coal "end up" somewhere. Air pollution is not acceptable, nor is contaminated drinking water or a despoiled landscape. The costs of using coal remain, whether they are in measurable costs of control and proper disposal, or in the hidden costs of the nation's health and safety.

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CHAPTER 10

ECONOMIC FACTORS INFLUENCING INDUSTRIAL FUEL CHOICE DECISIONS

Although in recent years public attention has been focused upon the environmental impacts of converting oil- or gas-fueled energy systems to coal, shifting to coal entails economic effects as well. Economic considerations are of particular importance to industrial firms. This chapter addresses these considerations from three related perspectives. First, the cost of steam is compared for conventional and advanced coal technologies and between conventional coal-fired boilers and natural—gas-fired boilers.* A sensitivity analysis is included to detail the extent to which variations in boiler size or operating parameters affect the cost of steam. Described second are the modes by which economic factors external to system costs may influence investment decisions. Finally, the relationship between projected future prices and availability of fuels, subjective probabilities of cost and supply, and industrial fuel choice decisions are analyzed on an industry- and region-specific basis.

STEAM COST COMPARISONS AND SENSITIVITY ANALYSIS

Costs of Alternative Coal Technologies

The site-specific nature of the costs of boilers and of steam production, as well as the developmental stage of some of the technologies, make it impossible to state costs precisely. Nevertheless, for the purpose of comparison, approximate costs are compiled in Table 41. These costs are based on information prepared in support of the Environmental Protection Agency's studies of possible revisions to New Source Performance Standards for industrial boilers. Standardized costing formats were employed in these reports. Therefore, much of the uncertainty regarding the basis of cost information has been removed, and the systems are compared in an internally consistent manner. Annualized costs have been adjusted, however, to reflect the lower load factor, 45 percent, and somewhat smaller boiler size, 100,000 lb steam/hr, used as the reference system throughout this report.

The results show that the use of cleaned coal in conventional combustion increases the steam cost only marginally. It is assumed that, when all the benefits of using cleaned coal are properly accounted for, the net cost of steam produced by a boiler with flue-gas desulfurization (FGD) is the same

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*All costs in the following chapter are expressed in mid-1980 dollars.

TABLE 41. SUMMARY OF APPROXIMATE COSTS[a]

Technology	Eastern coal		Western coal	
	Total capital investment, $\$10^6$	Cost of steam $\$/10^6$ Btu	Total capital investment, $\$10^6$	Cost of steam $\$/10^6$ Btu
Conventional combustion (CC)	8.80	7.43	10.57	7.77
CC with cleaned coal	8.96[b]	7.71	--	--
CC with FGD	10.12	9.79	11.82	9.21
CC/FGD with cleaned coal	10.20[b]	9.79	--	--
FBC	9.83	9.29	10.05	7.55
FBC with cleaned coal	9.99[b]	9.29	--	--
Low-Btu gasification plus boiler	12.80	12.57	11.77	10.74

[a] Basis: Boiler with 100,000 lb/hr of steam capacity (approximately 125 x 10^6 Btu/hr fuel input) with a load factor of 45 percent.

[b] Includes proportional share of the capital cost of a large coal cleaning plant supplying fifty 100,000 lb/hr steam plants.

whether cleaned or uncleaned coal is used; the same observation applies to fluidized-bed combustion (FBC). The benefits of using cleaned coal, particularly in conjunction with FGD or FBC, include: lower coal transportation costs, lower ash and other solid waste disposal costs, lower coal pulverizing costs, lower maintenance costs, increased plant efficiencies, longer plant life, and increased boiler availability (1).

For Eastern coals, FBC appears to be slightly less costly than FGD, while for Western coals, the differential is greater. For both technologies, in spite of higher capital costs for Western coal, the steam cost is less than for Eastern coal. Three factors contribute to this: (1) lower coal cost, (2) lower sulfur content, and (3) the presence of alkaline components in the coal that aid in capturing sulfur, thus reducing the amount of added reactant required for sulfur removal. Since, on the basis of the information supplied, FBC is assumed to require more reactant than FGD, the second and third factors affect the FBC cost more favorably than they affect the FGD cost.

The costs shown for the low-Btu gasification system are the highest of the technologies studied. The capital cost of the gasifier makes the total capital investment 25 percent higher than for the next most expensive system. The added capital cost in turn reflects adversely on the steam costs, which are 28 percent higher for the low-Btu system than for the next most expensive system. This capital burden becomes more costly as the load factor goes down because the capital-related charges are distributed to a smaller annual output. For this reason, the use of low-Btu gas is expected to be very uneconomical, except in applications where the system can be operated at high load factors.

Comparisons to Gas-Fired Boilers

In order to provide an indication of the magnitude of costs associated with coal-fired boilers compared to units fueled with natural gas, annualized steam costs have been calculated for two generic industrial systems. Baseline cost data are those developed by ICF, Inc. (2). Detailed cost figures are provided in the appendices to the ICF report, and the reader is referred to these for further information.

Costs for each system are those for installing a new boiler system in an industrial plant located in the Great Plains (CTA Region VII). Depending upon various site-specific circumstances, actual costs could be higher or lower than the following estimates for firms replacing an existing gas-fired unit with one capable of burning coal. The intent here, however, is only to express the relative cost differentials between systems and to test the sensitivity of steam costs to variations in boiler size, capacity utilization rate, capital charge rates, operation and maintenance costs (excluding fuel), and installation of stand-by boilers.

The coal-fired boiler systems burn high sulfur coal and are capable of meeting the emission reduction requirements as promulgated under the Clean Air Act and 1977 Amendments. Scrubbers are used for sulfur dioxide (SO_2) removal, and fabric filters (baghouses) are employed for particulate control.* Boilers burning natural gas are assumed to need replacement after 15 years. Coal boilers are assumed to have a 30-year useful life and the pollution control equipment requires replacement after 15 years. Fuel prices used in the cost comparisons are as follows:

Midwestern Coal	Base Price, $\$/10^6$ Btu	Annualized Price (30 yr), $\$/10^6$ Btu
50,000 lb steam/hr	1.96	1.96
100,000 lb steam/hr	1.75	1.75
200,000 lb steam/hr	1.56	1.56
Natural Gas		
All Boilers	2.87	3.78

Estimates of coal prices have been derived from prices reported by Oak Ridge National Laboratory (3). Coal prices are scaled according to boiler size in order to reflect the more favorable contracts available to larger users. The real price of coal is assumed to remain constant over the life of the boiler. On the other hand, the price of natural gas is assumed to increase more rapidly than inflation, escalating at a rate of 2 percent per year over the 30-year investment life. Such assumptions are, of course, somewhat simplistic. However, for reference comparisons of steam cost, it is reasonable to assume that the real price of gas increases more rapidly than the real price of coal. A more detailed analysis of future fuel prices is presented later in this chapter.

Table 42 illustrates the basis of cost comparisons for a boiler producing 100,000 lb steam/hr under reference assumptions. Note that capital costs are the largest annual cost component of the coal-fired boiler, while for the natural gas-fired system, fuel costs predominate.

Cost Sensitivity: Boiler Size

Annual steam costs as a function of boiler size are compared in Table 43. As shown in the table, steam costs are higher for a coal-fired system regardless of boiler size. These cost estimates further reveal the influence of the economies of scale associated with coal-capable energy technologies. The cost of steam under reference assumptions decreases from $10.01 for the smallest

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*Performance standards under the Clean Air Act and Amendments would not necessarily apply to boilers producing less than 200,000 lb/hr. However, many state regulations stipulate performance standards for small boilers, and national standards for small boilers are currently being investigated. Sulfur dioxide control was assumed to be 80 percent for the smallest unit and scaled to 90 percent for the larger. Particulate control is assumed to be 99.5 percent for all units.

TABLE 42. EXAMPLE OF COST COMPARISON FORMAT FOR 100,000 LB/HR BOILER SYSTEM[a]

Capital costs	Coal	Gas
Total 30-year costs ($\$10^3$)	7,779	1,518
Capital charge rate (real, %)	19.23	19.23
Annualized capital cost (30 year)	1,496	292
Total 15-year costs ($\$10^3$/year)	2,483	867
Capital charge rate (real, %)	21.10	21.10
Annualized capital cost (15 year)	524	183
Total annualized capital cost ($\$10^3$/year)	2,020	475
Total capital investment ($\$10^3$)	10,123	2,349
Operation and Maintenance Costs		
Fixed costs ($\$10^3$/year)	553	321
Variable costs @ 100% load factor	700	23
Load factor (capacity utilization rate, %)	45	45
Total annualized O&M costs ($\$10^3$/year)	869	241
Fuel Costs		
Fuel costs ($\$/10^6$Btu)	1.74	3.78
Fuel consumption (10^9Btu/year)	555.8	543.6
Annualized fuel costs ($\$10^3$/year)	973	2,055
Steam Costs		
Total annualized costs ($\$10^3$/year)	3,862	2,771
Steam output (10^6lbs/year)	394.2	394.2
Total steam costs ($\$/10^3$lb steam)	9.79	7.03

[a] All costs are given in mid-1980 dollars.

TABLE 43. SENSITIVITY TO BOILER SIZE[a] (LOAD FACTOR = 45%)

	Boiler capacity (10^3 lb/hr) 50	100	200
Coal			
Reference	11.44	9.79	8.43
Uniform fuel price	11.13	9.79	8.69
Natural gas	7.54	7.03	6.66

[a] Figures are given in dollars required to produce 1000 lb steam.

boiler to \$7.38 for the largest. As mentioned previously, however, some of the scaling effect is produced by the lower coal prices available to larger consumers. Yet, even when a uniform price of fuel is applied (\$1.75/10^6 Btu), economies of scale remain significant. Capital costs of coal technologies are obviously more sensitive to factors of scale. Conversely, steam costs for boilers fired by natural gas are rather insensitive to boiler size.

Cost Sensitivity: Load Factors

Curves depicting the cost of steam as a function of load factors are provided in Figures 36 through 38. For each boiler system size, units burning coal show a much greater sensitivity to load factors than do units fired by natural gas. The dramatic decrease in energy costs as a function of higher load factors reveals again the proportionately higher fixed costs of coal-fired steam systems. As the utilization rate increases, capital costs are spread across a greater energy output. Systems burning natural gas show only slightly improved steam costs as a function of load factor increases because, as a greater percentage of the available capacity is utilized, annualized fuel costs, which in gas-fired systems are proportionately higher than capital costs, increase substantially.

Clearly, load factors are a crucial variable with respect to steam costs, especially for coal-fired boilers. Although a great deal of uncertainty prevails, load factors for industrial boilers are generally low compared to the utility sector. PEDCo, Inc., examined capacity factors for small boilers and reported an average of about 28 percent (4). This is much lower than the commonly used figure of 45 percent. Utilization rates for various industries have been estimated in numerous reports, and are displayed in Table 44. Based upon these data, only in the petroleum, and perhaps chemical, industries is the majority of the available capacity used at a load factor in the 60 to 70 percent range. Conversely, in the food industries, most of the available

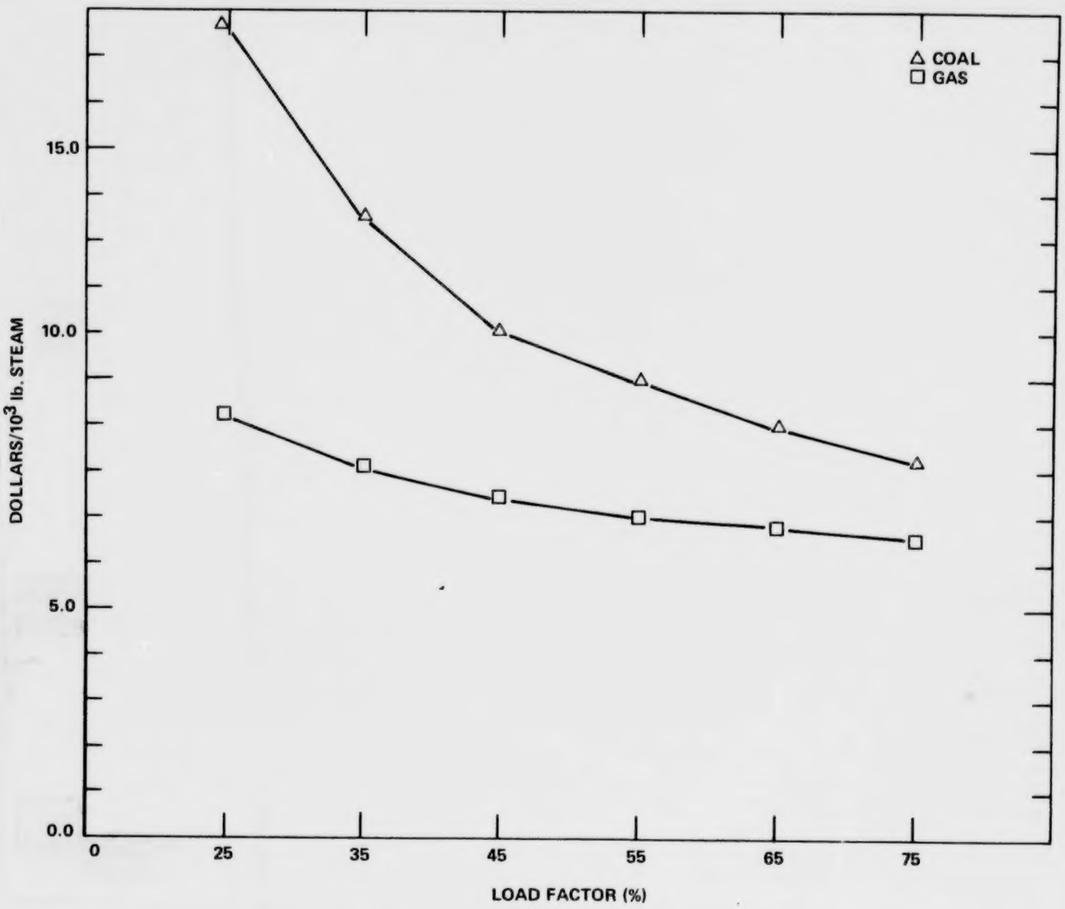

Figure 36. Sensitivity of steam costs to load factor: 100,000 lb/hr boiler.

boiler capacity is operated at less than 50 percent of maximum potential. Since industrial boilers are often in operation nearly full time, these modest capacity factors are much lower than would be anticipated (6). One possible explanation is that industrial plants are often redundantly equipped with boilers.

For many industrial firms, investment in a backup boiler--to be used during outages of the primary unit--improves the overall security of plant operations. Installation of standby boiler capacity, however, increases steam costs by raising the proportion of fixed costs to energy production. Table 45 compares the cost of steam for gas and coal systems incorporating backup boilers. In the case of the steam plant burning natural gas, the backup unit

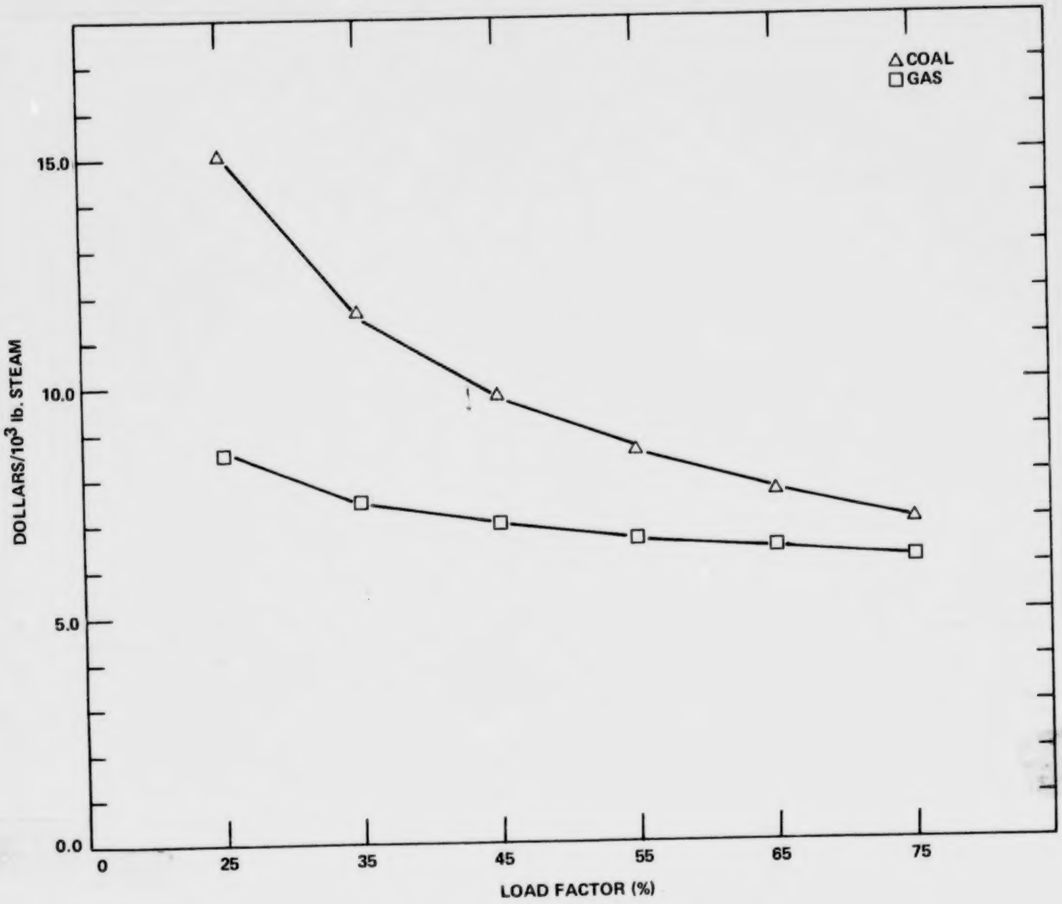

Figure 37. Sensitivity of steam costs to load factor: 50,000 lb/hr boiler.

is also gas-fired, while for the coal-fired system, costs are calculated for both gas- and coal-fueled standby boilers. Capital costs for the standby units have been adjusted according to equations generated by PEDCo (7). Load factor percentages given in Table 45 refer to the primary boiler system only. It is interesting to note that an industrial gas-fired steam system could incorporate a standby boiler and still be less costly than a coal-fired boiler without any backup capacity.

Another possible explanation of the generally low capacity utilization rates associated with industrial steam systems is that plants often experience wide fluctuations in energy demand. Thus a plant may need to produce 500,000 lb/hr of steam for a limited time, but only 200,000 lb/hr is required

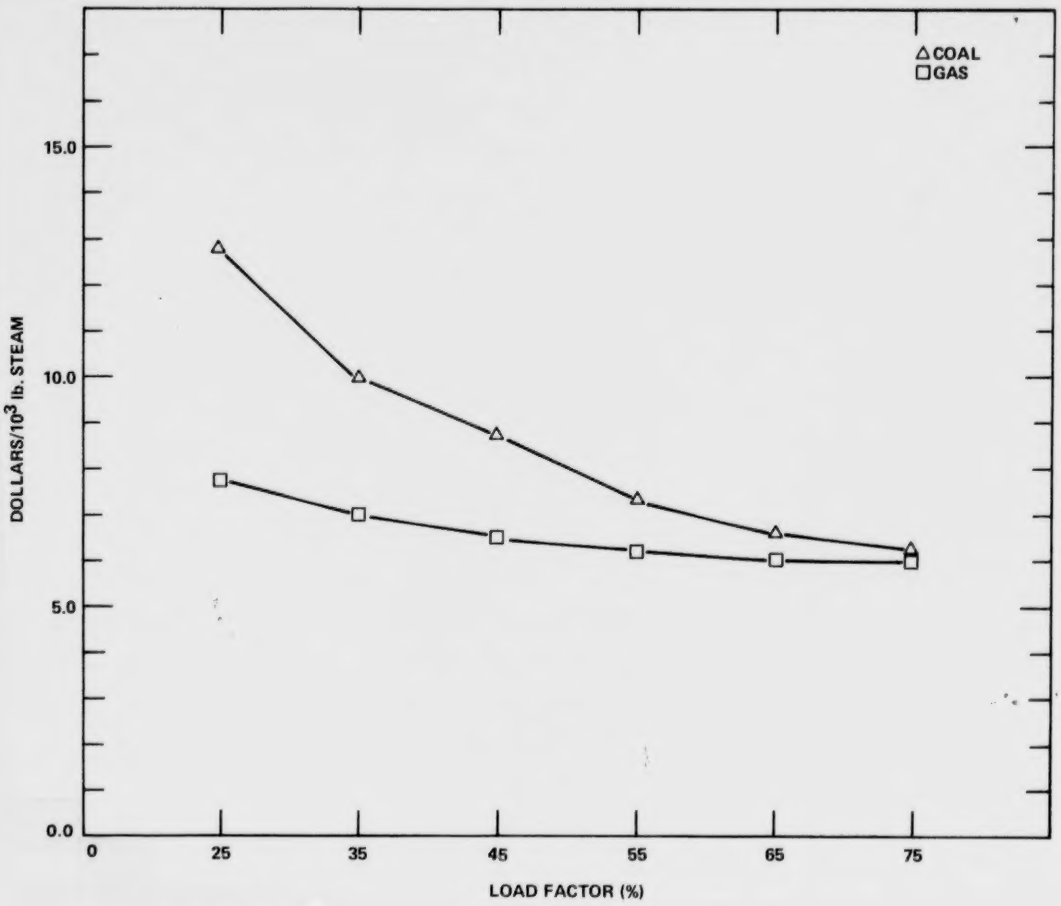

Figure 38. Sensitivity of steam costs to load factor: 200,000 lb/hr boiler.

for base-load demand. In such cases, a large boiler capable of satisfying temporary load fluctuations, or a separate peaking unit, would need to be installed. In either instance, the yearly utilization rate would reflect excess capacity. The significant point is that, owing to redundancy requirements and erratic or seasonal load fluctuations, boiler cost comparisons based upon lower capacity utilization rates (45 to 65 percent) provide, perhaps, a better approximation of actual annual steam costs to industrial firms.

Cost Sensitivity: Capital Charges

The capital charge rate consists of a number of factors, including depreciation of equipment, taxes, insurance, interest on debt, and the return

TABLE 44. LOAD FACTORS FOR INDUSTRIAL BOILERS

		PEDCo[a]		Exxon[b]		Acurex[c]		
Industry	SIC	Total	Active	$\bar{X}$	Size	<50	50-70	> 70
Food	20	30	33	46	39	55.4	30	24.6
Chemicals	28	36	42	66	56	19.3	30.8	50.0
Petroleum	29	63	47	66	62	10.7	19.2	70.2
Primary metals	33	53	55	46	35			
Steel						38.6	24.3	37.0
Aluminum						13.0	39.0	48.0
Equipment manufacturing	34	31	35	32	45			
	35	21	30	43	24			
	37	22	29					

[a] From a detailed survey of boilers in Indiana, New York, and Ohio conducted by PEDCo Environmental, Inc. (unpublished). "Total" refers to all boilers; "active" refers to boilers not used primarily as standby capacity.

[b] From reference 5. The left-hand column represents the average load factor for all boilers in each industrial grouping. The right-hand column gives load factors for boilers in the 100 to 150 x 10^6 Btu/hr (input) size range.

[c] Based on data from the NEDS data base. Load factor ranges are given at the head of each column. The figures in the columns are the percentages of boilers operated within each range of load factors.

TABLE 45. SENSITIVITY TO BACKUP CAPACITY[a]

	Boiler capacity (10^3 lb/hr)					
	50		100		200	
Load factor	45	75	45	75	45	75
Coal						
Reference	11.44	8.31	9.79	7.19	8.43	6.25
Coal backup	16.42	11.29	13.96	9.68	11.96	8.36
Gas backup	12.80	9.11	10.83	7.80	9.24	6.74
Natural gas						
Reference	7.54	6.63	7.03	6.32	6.66	6.09
Gas backup	8.90	7.44	8.07	6.93	7.47	6.58

[a] Figures are given in dollars required to produce 1000 lb steam.

that is expected on capital invested by industrial firms. The cost of investment capital (interest) can have a significant impact upon steam costs as well. Table 46 shows the sensitivity of steam costs to variable capital charges. In this case, the capital charge rate has been varied to encompass the range of standard return on investment rates that the major energy-consuming industries would probably apply to capital invested in boiler systems. As would be expected, coal-fired boilers are highly sensitive to capital charges. For example, annual steam costs for a reference boiler could increase by \$2.66 or decrease by \$1.15 because of variations in the cost charged to capital. Note also that under low capital charge assumptions, the annual cost of operating a large coal-fired boiler is less than that for an equivalent capacity gas-fired boiler operating at a 75 percent load factor.

Cost-Sensitivity: Operation and Maintenance Costs

Operation and maintenance costs are highly uncertain with respect to controlled coal-fired boilers. The uncertainty arises mostly from the site-specific nature of solid waste disposal costs and the relatively small amount of experience in operating SO_2 removal systems on industrial boilers (8). The sensitivity of the cost of steam to operating and maintenance costs was tested by doubling the variable portion--the great majority of which reflects pollutant control and waste disposal--of total operating and maintenance costs.

TABLE 46. SENSITIVITY TO CAPITAL CHARGES[a]

	Boiler capacity (10^3 lb steam/hr)					
	50		100		200	
Load factor	45	75	45	75	45	75
Coal						
Reference	11.44	8.31	9.79	7.19	8.43	6.25
High[b]	15.08	10.49	12.83	9.00	10.97	7.78
Low[c]	9.85	7.35	8.48	6.39	7.32	5.59
Natural Gas						
Reference	7.54	6.63	7.03	6.32	6.66	6.09
High[b]	8.45	7.16	7.72	6.72	7.19	6.41
Low[c]	7.14	6.39	6.73	6.14	6.42	5.95

[a] Figures are given in dollars required to produce 1000 lb steam.

[b] Assumes a weighted cost of capital of 25 percent.

[c] Assumes a weighted cost of capital of 10 percent.

Table 47 displays the results. As would be anticipated, a doubling of variable operating and maintenance charges for boilers fired by natural gas has a negligible effect. Coal-fired boilers are more sensitive to operation and maintenance costs because of pollution control requirements. Nonetheless, the sensitivity is relatively minor compared to all of the factors previously tested. It should be pointed out, however, that the unit costs employed in this analysis were developed for "greenfield" boiler installations. As was discussed in Chapter 4, retrofit applications of coal-fired industrial boilers may entail substantially higher costs for operation and solid waste disposal. In some instances, variable operation and maintenance costs might be expected to be as much as three to five times more than the baseline costs used above; this would have a significant effect on the cost of steam. Therefore, any great uncertainty surrounding the costs of operating and maintaining pollutant removal systems, and of disposing of solid wastes in retrofit applications, would be cause for concern from an economic perspective.

It is clear that, for coal technologies to become economically attractive compared to those fueled by natural gas, the price of gas must rise substantially above current levels. Yet, it is by no means certain that, once the annual cost of operating coal-fired boilers became cost-competitive with gas- or oil-fired systems, industrial firms would have a strong enough eco-

TABLE 47. SENSITIVITY TO OPERATION AND MAINTENANCE COSTS[a]

	Boiler capacity (10^3 lb steam/hr)					
	50		100		200	
Load factor	45	75	45	75	45	75
Coal						
Reference	11.44	8.31	9.79	7.19	8.43	6.25
High O&M cost	12.26	9.13	10.53	7.99	9.21	7.03
Natural Gas						
Reference	7.54	6.63	7.03	6.32	6.66	6.09
High O&M cost	7.56	6.65	7.06	6.34	6.70	6.11

[a] Figures are given in dollars required to produce 1000 lb steam.

nomic incentive to replace existing gas- and oil-fueled steam plants with coal. The following section describes the economic factors other than the cost of steam that are most likely to influence choices of boiler fuel and technology.

ECONOMICS OF FUEL CHOICE

The economics of fuel choice in the manufacturing sector are far more complex than in the utility sector. In manufacturing, the capital costs of replacing energy production equipment are not readily passed on to the consumers, and manufacturers must maintain their competitive position (6). The substantial capital investment required to convert to coal could affect a firm's competitive standing in a variety of ways. Replacement of existing gas or oil equipment, therefore, must be considered from the perspective of business decisions. The decision to convert to coal entails a thorough examination of capital availability, allocation, and investment strategies; of the impact a fuel change might have on present and future plant productivity; of the possible risks of losing (or of the potential for gaining) a competitive advantage in the market; and finally, an assessment of the costs versus the utility of converting to coal.

Capital Availability and Allocation

Owing to the finite capital resources available to most firms, economic considerations are foremost (9). As discussed previously, capital costs for coal-fired boilers are much higher than for gas/oil units of equivalent capacity. In some instances, the capital costs of replacing the steam system may equal the original investment in the entire manufacturing complex (3). Scale economies associated with coal technologies, and the magnitude of the capital costs of purchasing and installing them, combine to make the conversion to coal a major investment decision.

Availability of the necessary capital is subject to three major constraints. First, for many firms, replacement of energy facilities is an unscheduled investment (10). Capital resources may already be committed to other projects and these commitments might extend well into the future. Second, federal monetary policy and normal business cycles may, from time to time, sharply reduce the amount or raise the cost of capital available for lending. Finally, lending agreements between banks and industrial firms often stipulate that a given debt-to-equity ratio be maintained; the portion of the conversion project that could be debt-financed might be limited (3). The fraction of the capital investment that would have to come from existing equity assets would not be available for other uses, and, in addition, the amount of credit available to finance future investments would be reduced. Thus, financing a shift to coal becomes a question of strategic allocation of finite capital resources. Conversion to coal must become a sufficiently attractive investment to compete for capital with other projects.

Investment Strategies

In order for a boiler replacement project to compete for scarce capital with other corporate projects, there must be an expectation that the investment in coal-fired technologies will provide a measurable return on investment. A firm must also consider the effect the investment will have upon its competitive position in the market place. A company that invests capital in coal facilities, while a competitor invests in modernization or in expansion of production capacity, will be placed at a disadvantage unless the conversion to coal results in a relatively short-term advantage in operating costs (3). Should savings in operating costs not quickly materialize, the firm converting to coal might experience losses in profit, declining market shares, or it might sacrifice future competitiveness owing to the unavailability of capital for technical innovation in production processes. Substitution of coal for gas and oil in industry may thus have to be accomplished uniformly on an intra-industry-wide basis (6,11).

Additional aspects of investment financing need to be incorporated into the decision-making process. An existing investment in gas or oil energy systems that has not been amortized effectively raises the total capital cost of boiler replacement. Full depreciation of existing capital stock may not occur for many years. Investment credits, depreciation allowances, and similar deferral schemes may have little effect on low margin industries, such as

steel and cement manufacture, where current income is insufficient for full allowance benefits to be realized (12).

Another economic factor influencing company choices of boiler fuel and technology is the relative contribution of energy costs to total costs. In companies where energy costs make up a significant portion of total costs, there is reason to accept the capital demands, risks, and inconveniences of a coal-based system, if the system will reduce significantly the energy and, hence, total costs. Conversely, for companies where steam accounts for but a small portion of total costs, coal systems may pose unacceptable risks and opportunity costs. The most important of these risks relate to boiler system reliability.

A related point is how a coal-fired boiler system makes demands on a firm's limited capital resources. Typically, candidate investment projects are evaluated to determine which are likely to yield positive net benefits over their lifetimes. When, however, a company has more economic projects than it has debt or equity resources to fund, it prioritizes projects in accordance with the organization's overall goals. Firms with high energy costs will give more attention to projects to reduce energy costs than will firms with low energy costs. Low energy cost companies may, for example, see more lucrative returns from investments in technologies to increase labor and material efficiency, or from expenditures in product development and marketing activities. For the larger firms in the manufacturing sector, capital availability and allocation will probably present only minor problems. But for many industries, the capital demands of coal conversion may present risks of losses in competitive position or sacrifices in future ability to achieve rapid technical innovation and expansions in productive capacity.

RISKS IN CONVERTING TO COAL

Commitment to Coal

One impact, or perhaps risk, of converting to coal is that, owing largely to the significant capital investment required, the prospective user will tend to be "locked in" to coal use for a number of decades. Until the investment has been amortized, users will be hindered from switching away from coal to another energy source. Although coal boilers can be more easily converted to burn oil or gas than vice versa, a substantial fraction of the total capital investment will be for those facilities ancillary to the boiler itself. Just as the current investment by industry in gas or oil boilers will hinder rapid conversion to coal technologies, the capital cost of conversions, should they occur, will impede any future attempts to displace coal use in the manufacturing sector.

The manner in which users contract for coal supplies will also affect the degree to which they become committed to coal use. Currently, the status of the coal marketing infrastructure indicates that most industrial users will prefer to buy coal on short-term contracts or intermittently on the spot market (10). However, the declining output from small coal mines producing especially for spot markets, the price instability of spot coal, decreases in surplus supply due to tighter management practices, the incentive provided by the need to obtain supplies of specific types of coal, and the fact that a reliable and continuous supply is indispensable for industrial users, all suggest that longer term contracts will be sought and entered into by firms converting to coal. Long-term contractual agreements would further constrain a firm's ability to switch away rapidly from coal to an alternative energy source. Thus, replacement of gas or oil boilers with those capable of burning coal entails a long-term commitment to coal--perhaps 20 to 30 years at a minimum. Economic considerations largely preclude the efficacy of using coal temporarily, as a short-term transitional fuel.

Productivity Losses

A firm considering a changeover to coal must not only be cognizant of the potential risks of losing competitive standing and operational flexibility, but also must consider the risks of losing productivity. As discussed in Chapter 5, space requirements may dictate that a new coal-fired steam plant be located suboptimally with respect to achieving an integrated plant layout and providing the most efficient service to process load centers. Depending upon end use requirements, energy losses experienced as a result of moving the boiler facility to the periphery of the plant complex could adversely affect productivity. Similarly, alterations in plant layout to accommodate a coal-based energy system might be achievable only at the expense of some decrease in the ease of materials transport and the efficiency of overall plant operations. Land procured to accommodate coal storage, preparation, and waste disposal operations but that was formerly allocated for expansions of productive capacity would thereby represent another loss in future productivity. Replacing existing boilers with coal technologies may, therefore, impose quite significant opportunity, as well as capital, costs.

The most obvious potential for conversion to result in productivity losses is in the plant down-time experienced because of forced outages of the steam system. Because at least the larger coal boiler systems will need to be erected at the site, and because of the complexity of the replacement project, conversion to coal might necessitate lengthy outage times. Facilities or sources to make up for the lost capacity simply do not exist at most manufacturing establishments (6). Installation of a coal-fired boiler would, in such cases, disrupt a plant's productivity.

Once a coal system is installed, the boilers (and other equipment as well) will require relatively frequent maintenance. Although soot blowers, chemical additives, and careful combustion control can lessen the maintenance requirements (while raising costs), coal-fired boilers always require some shutdowns for cleaning operations and part replacement. If a high level of pollution control is mandated, forced outages can be anticipated to occur more frequently. Flue-gas scrubbing devices are sophisticated pieces of equipment which do not, as yet, have a long history of operating reliability. Unless excess capacity is available, outages for boiler maintenance or forced shutdowns due to pollution control equipment failure will disrupt manufacturing operations and potentially reduce productivity. For some industries, interruption of steam supply could be ruinous.

It is probably for these reasons that industry commonly maintains capacity in excess of normal operating needs. The much lower capital cost of gas and oil units has made installation of redundant capacity an economically viable strategy. Yet, as was shown above, economical use of coal technologies requires that only large boilers be installed and that these be operated nearly continuously. Thus the flexibility in plant operations gained by deploying many small boilers and the security of plant operations gained by liberally installing backup capacity would be foregone in a widespread shift to coal in the industrial sector.

The effects that alterations in plant layout, outages suffered during equipment maintenance, and reallocation of land will have on overall plant productivity are largely site- and industry-specific. Still, these factors must be considered and satisfactorily resolved before an industry will change over to coal use. Failing resolution, these considerations will add a degree of uncertainty to the decision-making process.

Infrastructural Capabilities

Deficiencies in the coal transportation and supply infrastructure will also increase the real or perceived risks of converting to coal. Costs of hauling coal are rather unpredictable. Should the demand for coal rise sharply, competition among users for reliable transportation will increase concurrently. Increased demand, in combination with finite available capacity, could substantially escalate the costs of transporting coal. Smaller users would be particularly vulnerable since they will be at a disadvantage if they must compete for limited transportation services. Similarly, the uncertainty surrounding the long-term reliability of supply will tend generally to amplify the risks of conversion. Potential users in the manufacturing sector must be convinced that the labor unrest, which in the past caused major interruptions in coal supply, will not be likely to occur in the future.

Least-Cost Criteria

The considerable problems and inconveniences associated with industrial coal use remarkably complicate, and to some extent even obscure, the economic rationale of fuel choice. Each constraint or inconvenience has at least the potential to significantly raise the effective costs of using coal over the costs of using other fuels. The use of oil or natural gas has economic value for business enterprises above and beyond actual steam costs. The large capital investment in existing gas or oil facilities also contributes to industry's tolerance of significantly higher prices for these fuels. Absorbing higher fuel costs for gas or oil will be, for many firms, less risky than making the new capital investment required to shift to coal. Steam costs for industry often do not comprise a large fraction of their total operating expenses, and since gas or oil is less troublesome to handle at an industrial site, accepting higher prices for preferred fuels can often be economically justified as part of wider business strategy. Recently, most boiler modifications and replacement projects have been oriented toward incorporating the ability to burn a wide range of liquid and gaseous fuels; security of fuel supply is, at the present time, a greater determinant in fuel/technology choices than is least cost (13). As long as manufacturers feel reasonably confident of being able to obtain adequate supplies of natural gas or oil, the operational security and the convenience inherent in the use of these fuels will justify their higher price.

Many informed observers of trends in industrial energy consumption and fuel choice agree that the final decisions on boiler technology are often made for reasons other than the lowest expected steam generating costs (14). The risks involved in diverting capital away from projects more certain to produce a rapid return on investment, the possible opportunity costs of conversion, the risks of becoming committed to a particular mode of business operations, and the risks of losing productivity, challenge the notion that fuels will be selected solely on the basis of measurable steam costs. Within the industrial sector, the convenience and practicality of continuing to use natural gas or oil may well offset the rising costs for these fuels.

The extent to which a firm will pay higher steam costs for reasons of convenience is exceedingly difficult to determine. Industry in the past has been willing to pay a 10 percent premium for natural gas over oil, which suggests that a much higher premium would be paid for either of these fuels over coal (12). One recent study reported that acceptable steam cost differentials could range from 20 to 100 percent, depending mainly upon whether advanced pollution control equipment is mandated (15). And should decision-makers in business firms perceive coal-fired systems to be clearly less reliable than gas or oil units, such a perception would influence fuel choice almost without regard to calculated cost differentials (2).

FUEL CHOICE DECISION ANALYSIS

Clearly, the decision to burn coal as a boiler fuel can be influnced by a number of economic, technical, and organizational considerations, many of which are often not reflected in steam cost comparisons. It is equally clear that a quantitative analysis of industrial fuel/technology choice must be sensitive to inter-regional and inter-industry differences. Moreover, such an assessment should, in some manner, take into account the perceptions of plant managers and corporate officers in regard to the key economic variables affecting energy decisions. Through a consideration of these sensitivities and perceptions, a clearer perspective can be gained on the extent to which economic incentives exist to replace existing gas or oil boilers with coal-capable technologies. The following section presents an industry-specific analysis of fuel choice decisions and is adapted from related work conducted as part of the EPA's Coal Technology Assessment (16). In all of the following cases it is assumed that an existing gas-or oil-fired boiler requires replacement. The existing unit is assumed to have totally depreciated in value.

Methodology

Six industries will be considered: chemicals, petroleum, aluminum, steel equipment manufacturing, and food processing. The analysis will take into account industrial differences by considering industry-specific data on average boiler size, load factor, and expected returns on invested capital, all of which influence the traditional analysis of capital, operating and maintenance, and fuel costs. In addition, regional differences will be reflected in fuel costs and availability, as well as in the subjective probabilities that specific levels of price and fuel availability will occur. Probability functions are derived from information provided during the interviews, from literature review, and through a Delphi process involving the project personnel. Boiler system costs are the same as those used earlier in this chapter. Prices for natural gas are based upon data presented in the Department of Energy's Monthly Energy Reviews, and price escalation rates were developed from unpublished forecasts by the Gas Research Institute and the American Gas Association (17). Data on boiler size and load factors are taken from information presented earlier in this report. Weighted costs of invested capital (hurdle rates) were calculated on the basis of data gathered from a variety of sources (18, 19, 20). Input data are presented in Table 48. Note that two industries in the table have two regional locations.

Eight possible outcomes, or scenarios, were constructed in terms of variations in fuel prices and expected levels of supply. A probability function was attached to each node, or branch, of the probability tree, an example of which is given in Figure 39. A different set of probabilities was constructed for each of the eight industries; these are shown in Table 49. It is important to reiterate that these factors reflect, for the most part, intra-industry perceptions. Where information from the interviews was insufficient to provide high-confidence probability functions, as was often the case with respect to coal prices, probabilities were determined through extensive literature review (see Chapter 4) of past experience and current trends. At any rate, it should be emphasized that the probabilities are not intended to be precise determinants; rather, they are intended only to reflect the relative differences between industries in regard to regional location, size, and perceptions about the future availability and price of fuels. Note that all industries in the Gulf Coast region expect coal prices to increase in real value. This sentiment arises mostly from concern over transportation costs, which, for the Gulf Coast, comprise the majority of the delivered cost of coal. Conversely, industries in the Great Lakes region are generally confident

TABLE 48. INPUT DATA FOR FUEL CHOICE DECISION ANALYSIS

Industry	Location CTA region	Boiler size lb steam/hr	Load factor %	Weighted cost of capital[a]	Baseline coal price $\$/10^6$Btu	Rate of increase real %		Baseline gas price $\$/10^6$Btu	Rate of increase real %	
						High	Low		High	Low
Chemicals	VI	100,000	55	10	2.05	3.0	1.0	2.77	6.0	2.0
Petroleum	VI	200,000	65	15	1.75	3.0	1.0	2.77	6.0	2.0
Petroleum	II	200,000	65	15	1.56	3.0	1.0	3.67	6.0	2.0
Steel	III	200,000	45	10	1.56	3.0	--	3.67	6.0	2.0
Aluminum	VI	200,000	55	10	2.05	3.0	1.0	2.77	6.0	2.0
Equipment manufacturing	III	50,000	35	25	1.96	3.0	--	3.67	6.0	2.0
Equipment manufacturing	VI	50,000	35	25	2.30	3.0	1.0	2.77	6.0	2.0
Food processing	VII	50,000	45	25	1.96	3.0	1.0	2.87	6.0	2.0

[a] The capital recovery factor (CRF) was calculated according to:

$$\mathrm{CRF} = \frac{r(1+r)^N}{(1+r)^N - 1}$$

where

r = weighted cost of capital

N = life of investment, assumed to be 30 years.

Taxes and insurance were assumed to be 4 percent and were added to the CRF to give the total capital charge rate.

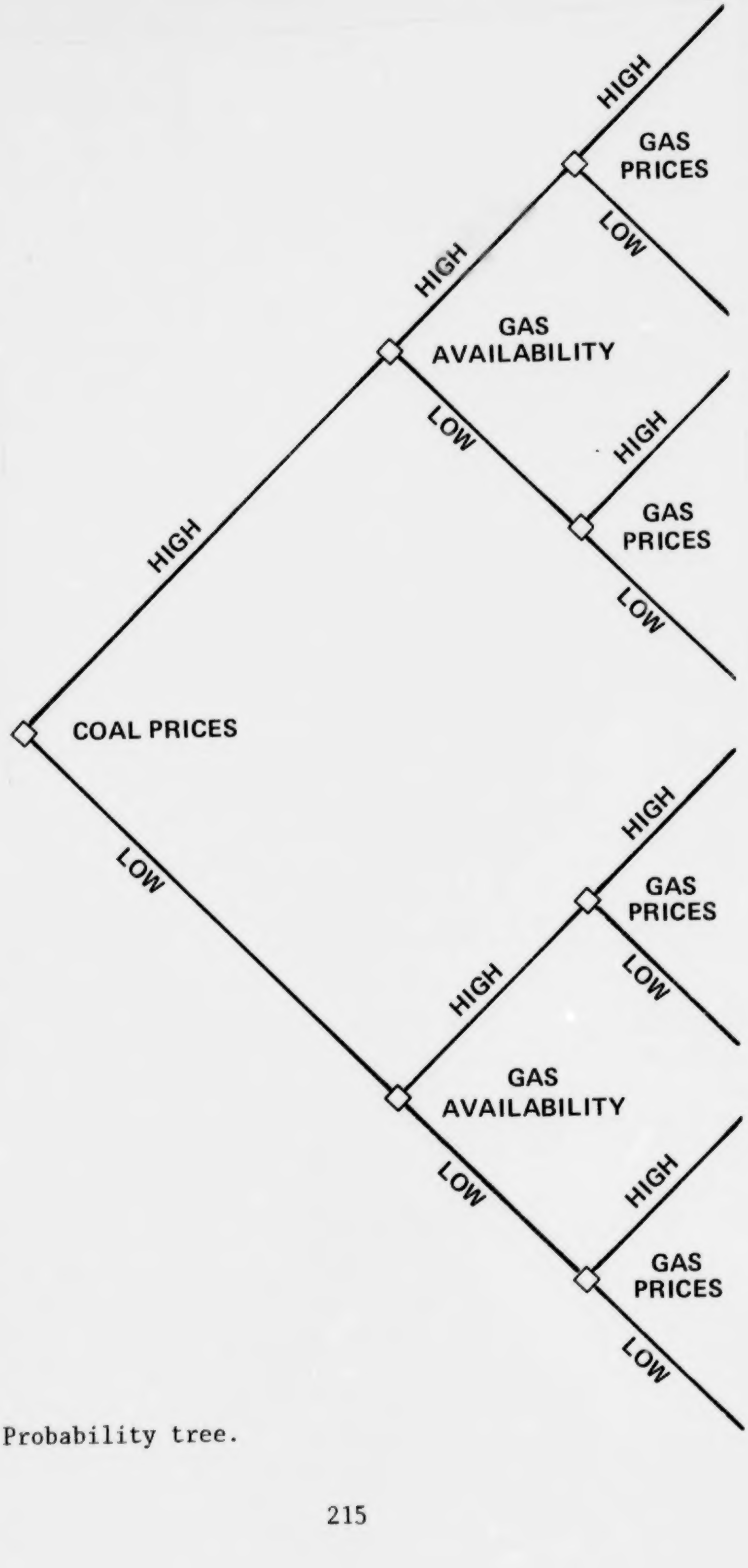
HIGH
GAS PRICES
LOW
HIGH
GAS AVAILABILITY
LOW
HIGH
GAS PRICES
LOW
HIGH
COAL PRICES
LOW
HIGH
GAS PRICES
LOW
HIGH
GAS AVAILABILITY
LOW
HIGH
GAS PRICES
LOW

Figure 39. Probability tree.

TABLE 49. PROBABILITY FUNCTIONS

					Gas prices			
	Coal prices		Gas availability		High availability		Low availability	
Industry	High	Low	High	Low	High	Low	High	Low
Chemicals Gulf Coast	0.80	0.20	0.90	0.10	0.55	0.45	0.65	0.35
Petroleum Gulf Coast	0.80	0.20	0.95	0.05	0.55	0.45	0.65	0.35
Petroleum Upper Atlantic	0.60	0.40	0.75	0.25	0.65	0.35	0.75	0.25
Steel Great Lakes	0.30	0.70	0.55	0.45	0.65	0.35	0.85	0.15
Aluminum Gulf Coast	0.80	0.20	0.85	0.15	0.55	0.45	0.65	0.35
Equipment manufacturing Great Lakes	0.40	0.60	0.60	0.40	0.70	0.30	0.85	0.15
Equipment manufacturing Gulf Coast	0.90	0.10	0.80	0.20	0.55	0.45	0.65	0.35
Food processing Great Plains	0.70	0.30	0.70	0.30	0.55	0.45	0.65	0.35

that the price of coal will increase only at the general rate of inflation. In both regions, however, declining supplies of coal to small users could push prices upward in the future. During the course of the interviews, there was a consistent perception that natural gas would be widely available. This perception was most sensitive to regional location, a facet which is reflected in the assignment of probabilities. The greatest uncertainty encountered in the interviews, and the greatest disagreement encountered during literature reviews and in other analyses, surrounds the future price of natural gas. On the one hand, deregulation of prices under the Natural Gas Policy Act will clearly result in higher prices. Yet, many believe that the initial price increases might stimulate production to an extent that supply/demand forces will gradually restrain further price increases. Thus, the probabilities attached to high or low gas prices are, in most instances, close together. The probability of high prices under a scenario of low availability is only somewhat higher, since many industrial managers believe that, should gas supplies be severely restrained, a re-imposition of price controls would be likely.

For each scenario and for each industry/region grouping, the costs of steam from a coal-fired system and an equivalent capacity gas-fired system were calculated and compared. When the availability of natural gas was predicted to be low, it was assumed that oil would be burned for 10 years of the 30-year investment. Oil was somewhat arbitrarily priced at 1.5 times the high price of natural gas in the Gulf Coast region ($9.14/10^6$ Btu). The results, discussed below, are displayed in three ways. First, annualized capital, operation and maintenance, and fuel costs are provided and summed to give the annual cost of steam under each scenario. Second, the difference in the cost of steam between the gas-fired system and the coal-fired system was calculated as a percent of the coal-fired boiler. Thus, negative values reflect instances in which a gas-fired boiler would be most economical, and positive values indicate that a shift to coal would be favorable. Each percentage value was then plotted as a function of the joint probabilities ([P] x [P] x [P]) of coal prices, gas prices, and gas availability that specify the scenario from which that value was derived. Boundary points were connected to delineate the area within which all values rested although only the individual points were actually derived. Finally, percent values were calculated as described above for each scenario and then multiplied by the probability that those results would occur. The resulting values were then summed to create an aggregate number that reflects the combined differences in steam costs and the probabilities of the scenarios.

Scenario Results

Chemicals - Gulf Coast--

Steam cost comparisons for a chemical plant located in the Gulf Coast (CTA Region VI) are displayed in Table 50. Costs for installing a gas-fired boiler could range from $6.60 to $10.95/10^3$ lb steam. Within the remaining four cases, however, the range of possible steam costs is quite small. Under assumptions of low coal prices, installing a coal-fired boiler would be most economical in all cases, with the exception of a situation in which the price of gas remains low and availability remains high.

TABLE 50. STEAM COST COMPARISONS FOR GULF COAST CHEMICALS INDUSTRY

Boiler Size: 100,000 lb/hr
Load Factor: 55%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	1501		356			
Annualized O&M cost ($ x 10^3/yr)	93.8		244			
Fuel cost ($/$10^6$ Btu)	High 3.06	Low 2.42	High 6.09		Low 3.88	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	2079	1644	4679	4046	3700	2578
Total energy cost ($ x 10^3/yr)	4518	4083	5279	4646	4300	3178
Steam cost ($/$10^3$ lb steam)	9.38	8.47	10.95	9.64	8.92	6.60

In Figure 40, the percent differences in steam costs for each of the eight possible combinations are plotted as a function of the probability of occurrence. As a general trend, probabilities tend to decrease as coal use becomes more cost-effective. Note, however, that the most probable scenario gives a result slightly in favor of coal use (+2.8 percent). Nonetheless, a considerable incentive still exists to continue using natural gas as a boiler fuel. This is especially true when probabilities are considered. The combined value reveals these trends, showing a slight preference for continued use of gas.

These results are inconclusive. The lack of a clear trend in favor of either gas or coal is, however, consistent with information gained through

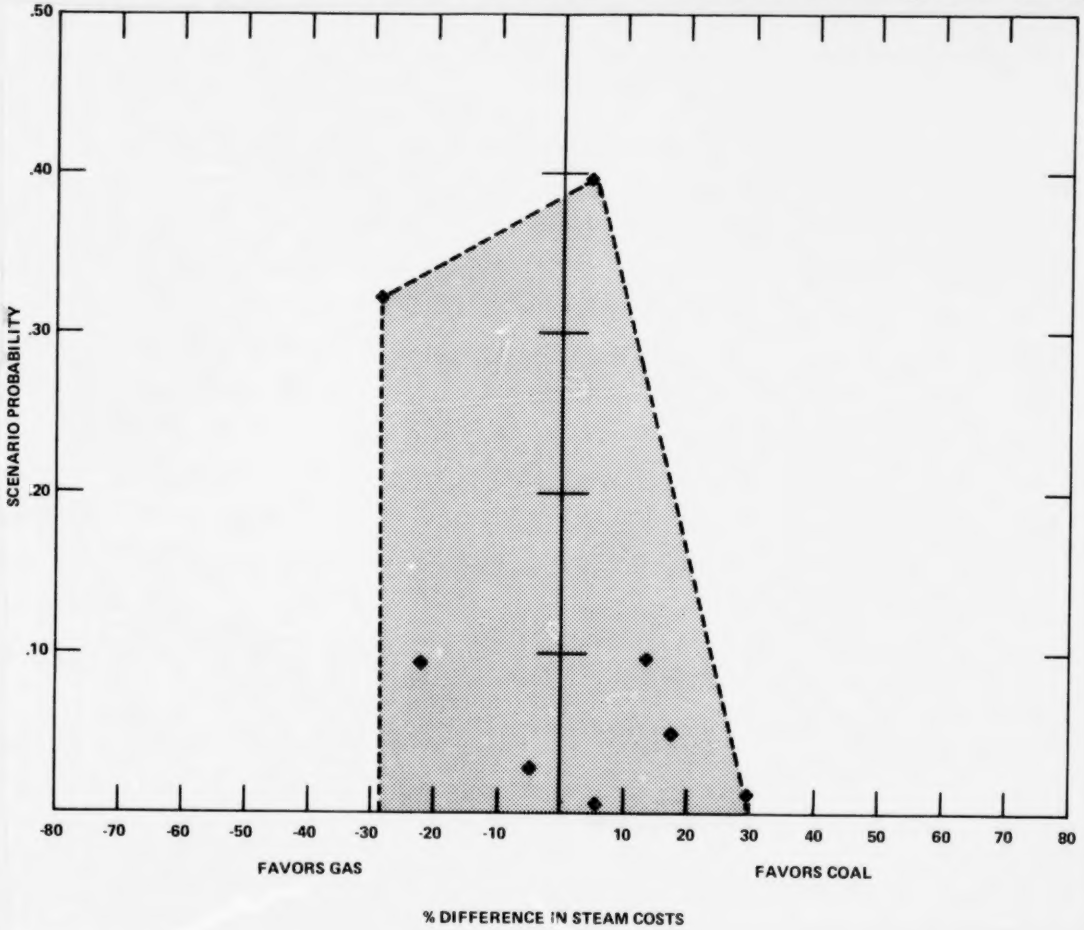

Figure 40. Comparative steam costs as a function of scenario probability: chemicals/Gulf Coast (combined score = -0.729).

interviews and from other sources. There are a number of additional factors that would tend to favor coal use. Of primary importance is the fact that energy costs constitute a high proportion of total operation costs, in some cases exceeding 50 percent. Therefore, even if the savings in steam costs from replacing an existing gas or oil boiler with one capable of burning coal is expected to be slight, it still might be enough to justify the investment. Similarly, the high contribution of energy costs to total production costs indicates that energy-related investments will compete equally for available capital. This fact is reflected in the lower capital charge rate used in the above calculations. The chemical industry is presently in quite good financial condition, and investments in high capital cost technology are unlikely to be constrained by a shortage of funds (see Appendix A).

Counteracting these incentives are uncertainty over the price and availability of coal (Texas and Louisiana account for 60 percent of the total fuel used by the chemical industry) and existing investments in gas or oil boilers. Until the coal supply/price situation in the Gulf Coast stabilizes somewhat, a changeover to coal will entail an undesirable element of risk, a risk many companies may be unwilling to take.

Petroleum Refining - Gulf Coast--

In Table 51, steam costs are compared for a boiler replacement project in a hypothetical refining complex located on the Gulf Coast. The lower coal prices (both "high" and "low") used for this industry, compared to a chemical plant in the same region, are due to the more favorable contracts available to larger users. The larger boilers and higher load factors of refining steam systems result in coal appearing as a more favorable option compared to the chemical industry. Only under a scenario of widely available natural gas supplies at a low price would coal appear uneconomical.

However, petroleum companies are still optimistic about being able to secure low cost supplies of gas, and these perceptions are evident in Figure 41. In effect, the greater economies of scale associated with larger boilers and the average higher rate of capacity utilization in the petroleum refining industry as compared to chemicals, shift the shaded portion to the right. The highest probability scenario--note that the probability of 0.418 is the highest encountered by any industry group--clearly favors a change to coal, and the potential savings that could be gained by using coal range higher (+43 percent) than the potential losses (-23 percent). The combined score reveals, on the whole, a small incentive to replace the existing boiler with a coal-capable unit.

Again, however, the results are somewhat inconclusive. Consideration of some qualitative factors tends to suggest that the incentive to switch to coal may be somewhat weaker than the empirical analysis indicates. For one thing, petroleum refineries have historically been sited in close proximity to urban or otherwise congested areas. One impact of restrictions on space would be substantially higher operation and maintenance costs for waste disposal and coal handling than those used in the preceding calculations. Although, as was shown earlier, steam costs are generally less sensitive to operation and

TABLE 51. STEAM COST COMPARISONS FOR GULF COAST PETROLEUM REFINING INDUSTRY

Boiler Size: 200,000 lb/hr
Load Factor: 65%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	3384		743			
Annualized O&M cost ($ x 10^3/yr)	1796		402			
Fuel cost ($/$10^6$ Btu)	High 2.61	Low 2.07	High 6.09		Low 3.88	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	4191	3324	11,120	9564	8746	6093
Total energy cost ($ x 10^3/yr)	9371	8504	12,205	10,709	9891	7238
Steam cost ($/$10^3$ lb steam)	8.23	7.47	10.72	9.40	8.69	6.36

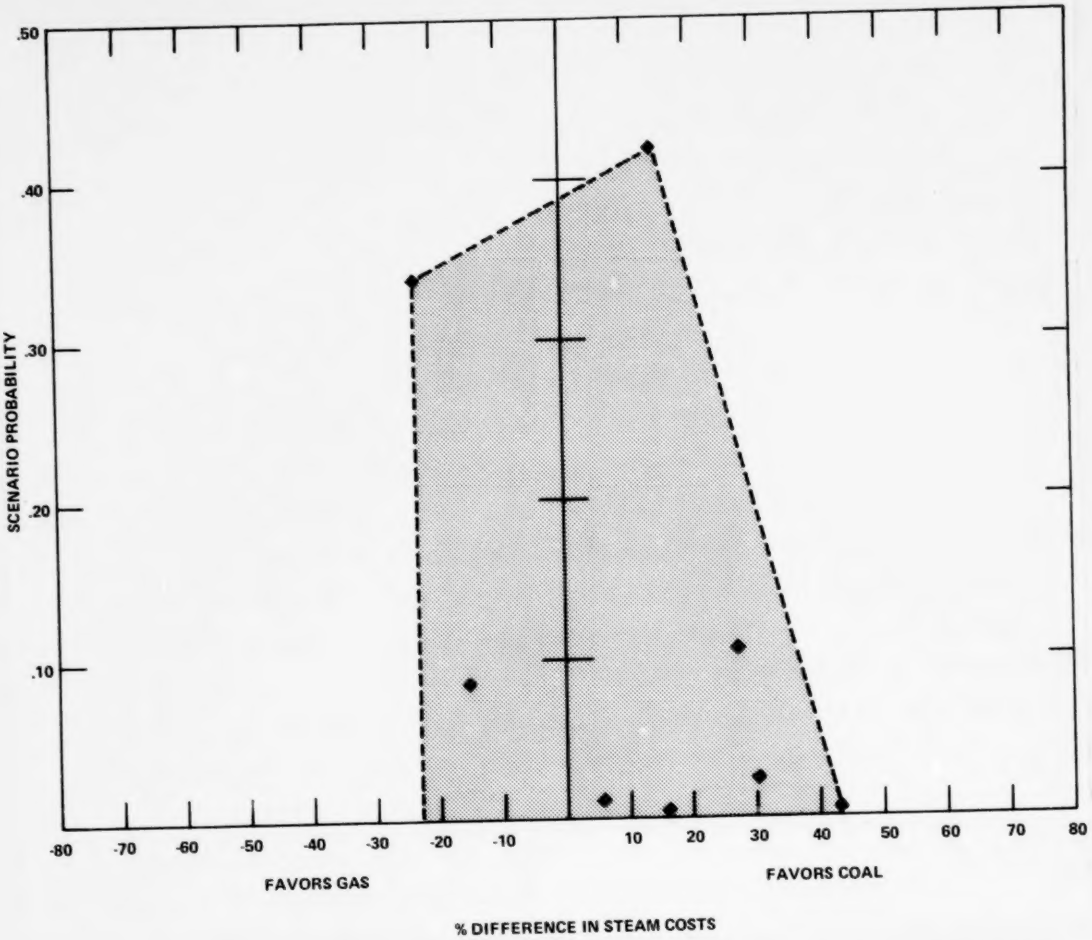

Figure 41. Comparative steam costs as a function of scenario probability: petroleum refining/Gulf Coast (combined score = +0.056).

maintenance costs, in the case of Gulf Coast refineries, they could very well tip the balance in favor of continuing to use gas. Of perhaps more influence is a growing trend within the industry to use greater amounts of waste products as fuel. Thus, boiler replacement projects could well involve neither coal nor gas.

Petroleum Refining - Upper Atlantic--

Conversely, a refinery located in the Upper Atlantic region would have a much greater economic incentive to replace existing gas or oil boilers with coal-capable technology. Only under conditions of high coal prices and low gas prices would the cost of steam produced from a gas-fired boiler be less than that from a unit burning coal (Table 52).

TABLE 52. STEAM COST COMPARISONS FOR UPPER ATLANTIC PETROLEUM REFINING INDUSTRY

Boiler Size: 200,000 lb/hr
Load Factor: 65%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	3384		743			
Annualized O&M cost ($ x 10^3/yr)	1796		402			
Fuel cost ($/$10^6$ Btu)	High 2.32	Low 1.84	High 8.07		Low 4.84	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	3725	2954	13,133	12,673	9751	7601
Total energy cost ($ x 10^3/yr)	8905	8134	14,278	13,818	10,896	8746
Steam cost ($/$10^3$ lb steam)	7.82	7.14	12.54	12.13	9.57	7.68

Yet, as can be seen in Figure 42, the single scenario that favors gas use does so only slightly. In the scenario having the largest overall probability of occurrence, a coal-fired system would be 55 percent cheaper than gas. As probabilities rise, the possible savings accrued by installing a coal-fired boiler also rise. A combined score of +44.5 shows a significant economic incentive to change to coal.

For the petroleum refining industry, then, regional location could apparently be the deciding factor in fuel choice decisions. In the absence of site-specific constraints, coal-use would appear marginally economic in the Gulf Coast region and would be clearly cost-effective for refineries located in the Upper Atlantic region. Capital availability should pose no serious industry-wide constraint, although boiler replacement projects would normally be at a moderate disadvantage in competing for capital with other projects. The potential savings do, however, appear great enough to offset the lower

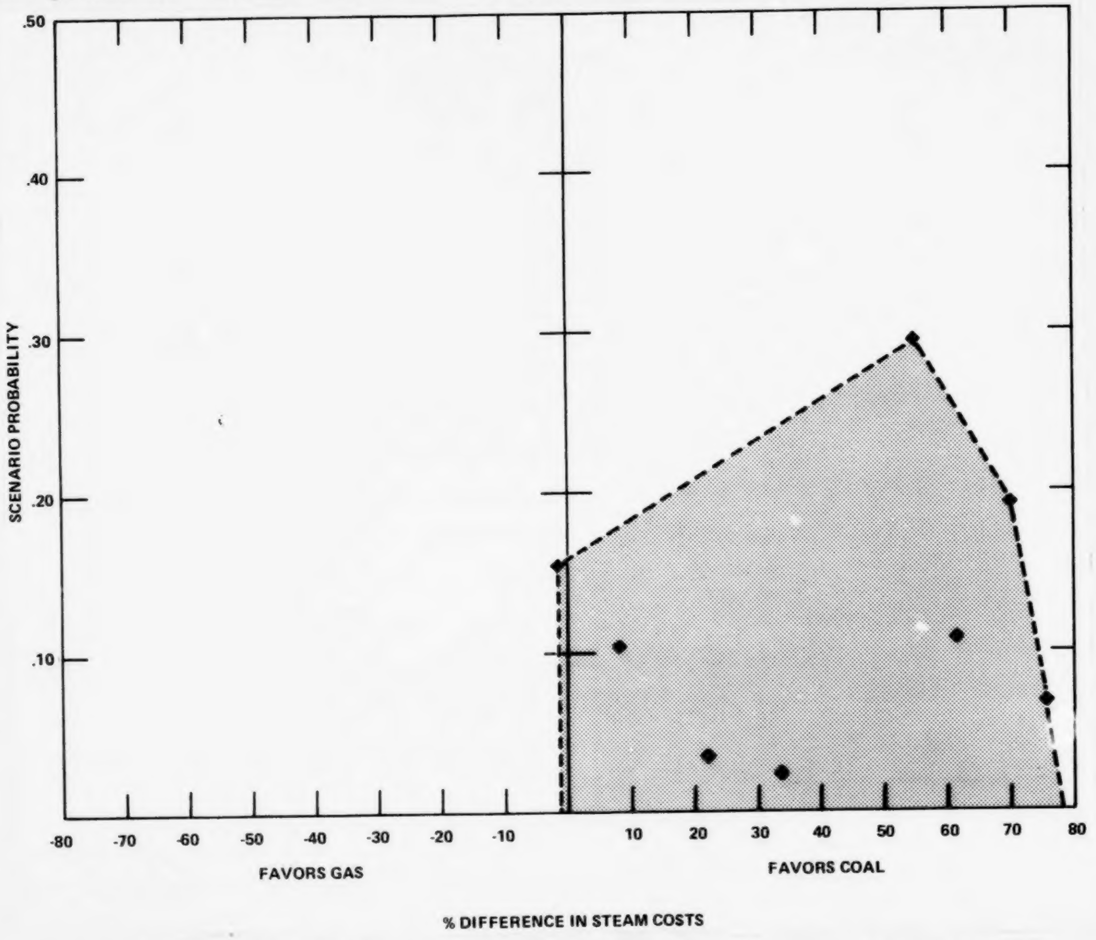

Figure 42. Comparative steam costs as a function of scenario probability: petroleum refining/Upper Atlantic (combined score = +44.5).

investment priority--as evidenced by the 25 percent rate of return employed in this analysis--accorded to boiler replacement projects.

Steel - Great Lakes--

One unambiguous signal from the interviews is the steel industry's willingness, indeed its preference, to burn coal. Existing capital stock, staff expertise, regional location, and traditional fuel supply arrangements combine to make coal the fuel of choice in the steel industry. It can be seen in Table 53 that, in nearly every instance, cost considerations clearly favor coal use. As mentioned in Chapter 3, the steel industry and the coal boiler industry have a long-standing, closely intertwined relationship. Iron and steel foundaries are often in close proximity to coal fields. Coal can be purchased at a low price, and supplies are generally quite reliable.

Moreover, perceptions within the industry with respect to the future availability and price of fuels serve to magnify the already objectively favorable cost comparisons. As evidenced in Figure 43, when the subjective probabilities of fuel supplies and prices are considered, coal use appears even more cost-effective. The combined score of +51.8 reveals the strong bias toward using coal.

If anything, the empirical results might actually understate the advantageous economics of burning coal in steel industry boilers. The interviews revealed that, in many instances, coal handling and preparation equipment is still in place. Capital costs for boiler replacement might, therefore, be substantially less than those used in this analysis. Furthermore, many existing boilers, whether gas or oil, were originally designed to burn fuels of a lower Btu content and thus could more easily be converted to -- rather than replaced by -- coal.

There are two main constraints, however, on expanding the use of coal within the steel industry. The first is a restricted availability of capital. Existing process equipment in the steel industry is generally obsolete. The past 10 years have witnessed a declining market for steel produced in the United States. In order to regain their competitive position, the industry is in the midst of an extensive program to replace old equipment with new, more efficient, process technology. As a result, boiler replacement or renovation projects, which would normally compete freely for each investment dollar, are currently given a lower priority. Compounding the problem is a general scarcity of equity capital. For the short term, until obsolete process equipment is replaced and the industry regains a competitive standing in world markets, accepting higher fuel prices for existing gas or oil boilers may be the most economical strategy. Second, the regional location of the steel industry places severe restrictions on allowable emissions. The incremental emission loadings that would be experienced in a change to coal would most probably violate air quality standards (see Chapter 7).

Aluminum - Gulf Coast--

Aluminum production, from ore reduction to final fabrication, is a highly energy-intensive process. Most of the steam used in aluminum production is

TABLE 53. STEAM COST COMPARISONS FOR GREAT LAKES STEEL INDUSTRY

Boiler Size: 200,000 lb/hr
Load Factor: 45%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	2513		559			
Annualized O&M cost ($ x 10^3/yr)	1523		394			
Fuel cost ($/$10^6$ Btu)	High 2.32	Low 1.56	High 8.07		Low 5.14	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	2579	1734	9092	8774	6968	5588
Total energy cost ($ x 10^3/yr)	6615	5770	10,045	9727	7921	6541
Steam cost ($/$10^3$ lb steam)	8.39	7.32	12.74	12.34	10.04	8.30

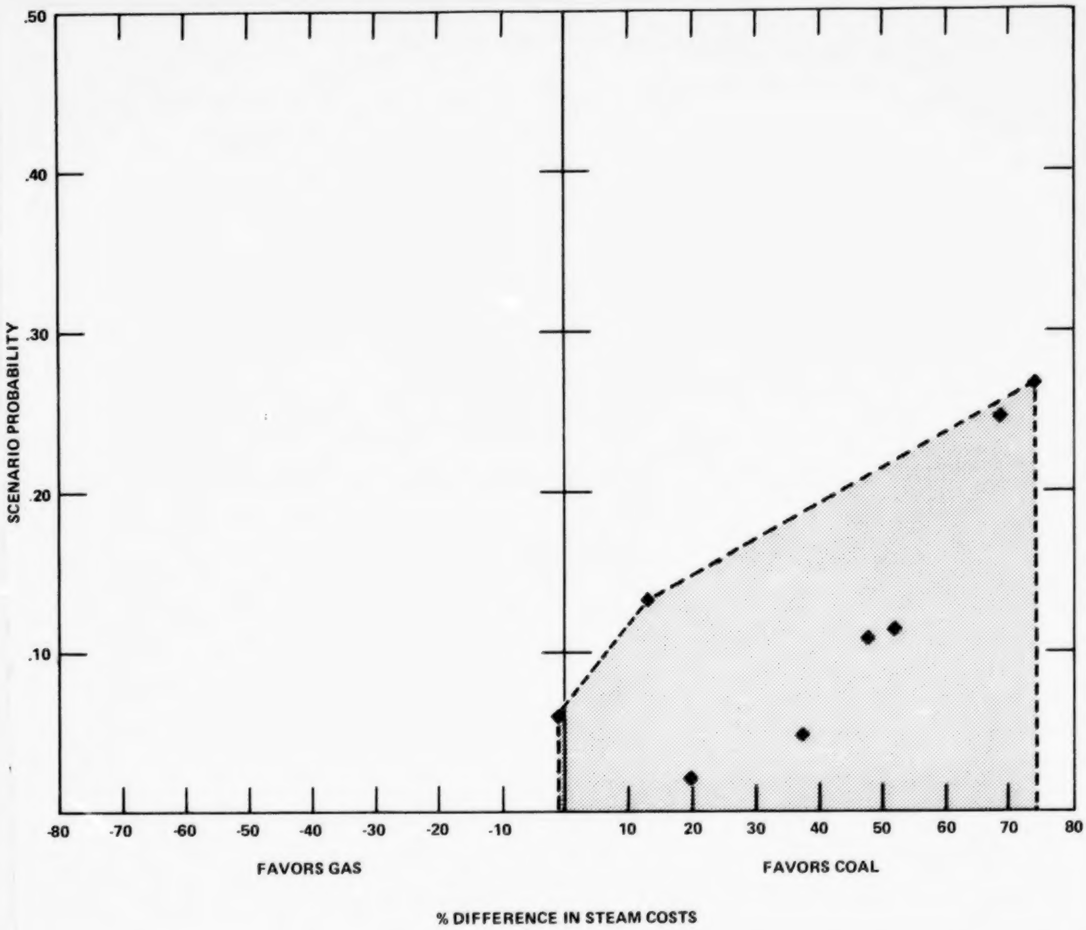

Figure 43. Comparative steam costs as a function of scenario probability: steel/Great Lakes (combined score = +51.8).

employed during the conversion of bauxite to alumina. Since most bauxite is imported from the Caribbean and South America, ore separation and preparation plants are located predominantly along the Gulf Coast. Were it not for their regional location, primary aluminum plants would rapidly begin to replace existing gas or oil boilers with coal-capable units. Yet, as can be seen in Table 54 and Figure 44, the prospect of widely available gas at a low price moderates against a switch to coal. Gas use is, however, only marginally economic (combined score = -2.75) under the assumptions employed in this analysis. Slightly higher prices for gas or high probabilities of curtailed gas supplies would alter these results significantly. Furthermore, the scenario of highest probability indicates an economic incentive to change to coal.

TABLE 54. STEAM COST COMPARISONS FOR GULF COAST ALUMINUM INDUSTRY

Boiler Size: 200,000 lb/hr
Load Factor: 55%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	3384		743			
Annualized O&M cost ($ x 10^3/yr)	1659		398			
Fuel cost ($/$10^3$ Btu)	High 2.61	Low 2.07	High 6.09		Low 3.88	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	3546	2813	9358	8092	7400	5156
Total energy cost ($ x 10^3/yr)	8589	7856	10,499	9233	8541	6297
Steam cost ($/$10^3$ lb steam)	8.91	8.15	10.90	9.58	8.86	6.53

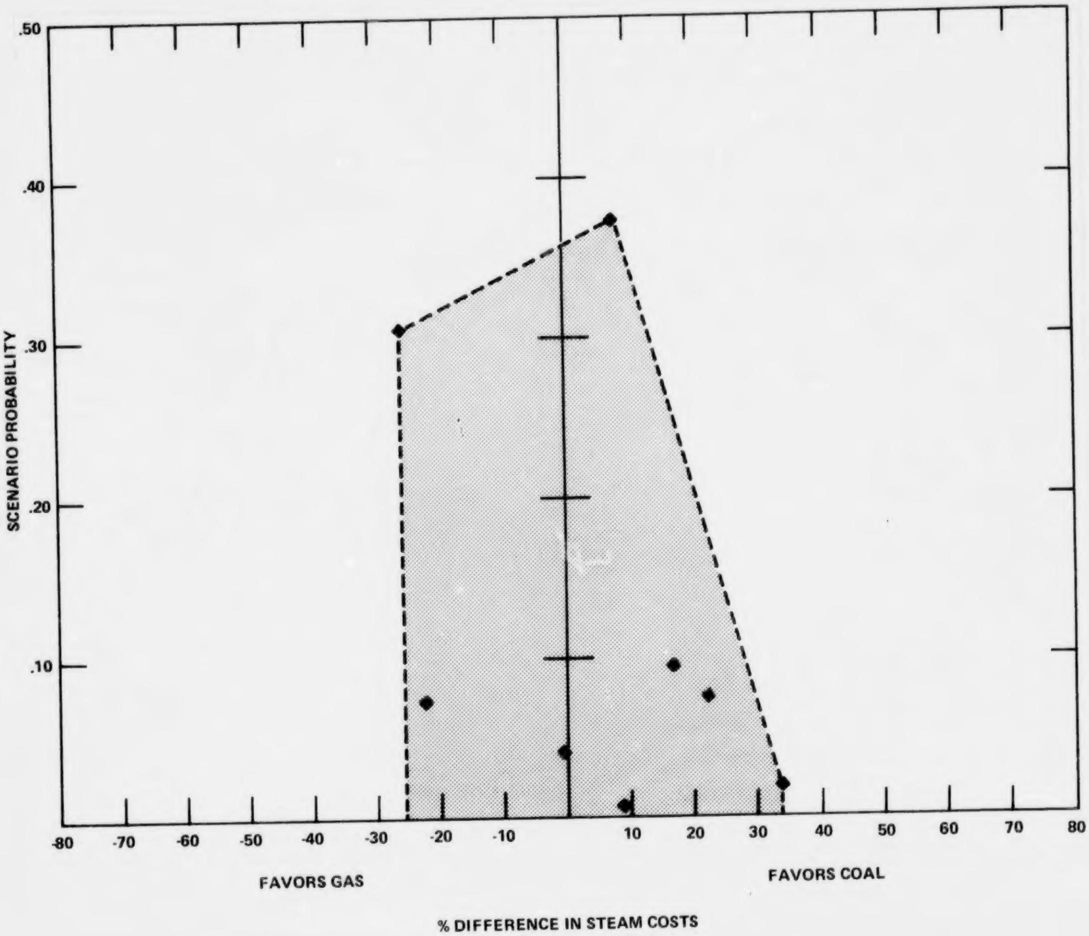

Figure 44. Comparative steam costs as a function of scenario probability: aluminum/Gulf Coast (combined score = -2.75).

Capital availability should pose no problems to the aluminum industry in boiler replacement projects. As in the chemicals industry, even a small improvement in steam costs can have a substantial impact upon total operating costs. The generally large boilers and high utilization rates characteristic of aluminum plants also tend to justify capital investments that allow the use of lower cost fuels. Finally, as indicated through the interviews, many aluminum plants are sited in rural areas where space requirements and air quality standards present less cause for concern.

Equipment Manufacturing - Gulf Coast--

Although our interviews focused upon automobile manufacturing (SIC 3711), energy consumption profiles for industries primarily engaged in the fabrication and assembly of metal equipment are all quite similar. Thus, the results provided here are applicable to the manufacture of heavy machinery (SIC 35), metal containers (SIC 34), and other transportation equipment.

The steam cost comparisons shown in Table 55 are distinctively one-sided toward continued use of natural gas in boilers in these manufacturing establishments. The price of coal to small factories in the Gulf Coast is expected to be exorbitant. Nonetheless, the price of coal has a relatively small effect upon the cost of steam from small coal-fired boilers operating at low load factors. As was evident in the sensitivity analysis earlier in this chapter, small coal-capable boilers are subject to severe diseconomies of scale. Owing largely to scale economies, capital costs have a proportionately greater effect on steam costs than they would in larger boilers. Thus, the annualized cost of natural gas remains substantially lower than the annualized capital costs alone of coal-fired units.

Figure 45 shows the clear advantage that small industries in the Gulf Coast perceive in continuing to use natural gas. As continued use of gas becomes more economical, probability factors also tend to rise. Note also the quite small range of expected cost differentials. Such a range reflects a relatively high degree of certainty that gas use will remain cost-effective. The combined score indicates that the price of natural gas could rise significantly beyond the price assumed here, and still offer the most economical boiler system.

Beyond the effect that small boilers and low load factors have upon the comparative economics of fuel choice decisions, the high capital costs of coal-fired boilers often cannot be justified in industries where energy costs are a small fraction of total operating expenses. The low priority that boiler replacement projects would be given within these industries means that the investment would have to offer a much higher return than investments that would increase material or labor efficiency. Thus, the capital cost of coal-fired boilers becomes even more pronounced. Similarly, the greater convenience and lower risks associated with gas-fired boiler systems are of exaggerated importance to non-energy-intensive firms. These considerations alone might favor continued use of gas, even at a penalty in steam costs.

Equipment Manufacturing - Great Lakes--

In contrast to the other inter-regional comparisons performed in this analysis, regional differences have only a moderate impact upon the comparative economics of fuel choice decisions for equipment manufacturing industries. As can be seen in Table 56, the cost of steam from a gas-fired boiler remains substantially less than that from a comparable coal-fired unit, regardless of fuel price and availability. A plot of the percent difference in steam costs as a function of scenario probabilities shows the extent to which regional differences influence fuel choice decisions for these industries (Figure 46). The general trends toward coal or gas are reversed; as the probabilities rise, the expected benefits of continuing to use gas decrease, since within the Great Lakes industrial belt there is a greater uncertainty

TABLE 55. STEAM COST COMPARISONS FOR GULF COAST EQUIPMENT MANUFACTURE

Boiler Size: 50,000 lb/hr
Load Factor: 35%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	1929		489			
Annualized O&M cost ($ x 10^3/yr)	462		147			
Fuel cost ($/$10^6$ Btu)	High 3.43	Low 2.71	High 6.09		Low 3.88	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	741	586	1489	1288	1178	821
Total energy cost ($ x 10^3/yr)	3132	2977	2125	1924	1814	1457
Steam cost ($/$10^3$ lb steam)	20.43	19.42	13.86	12.55	11.83	9.50

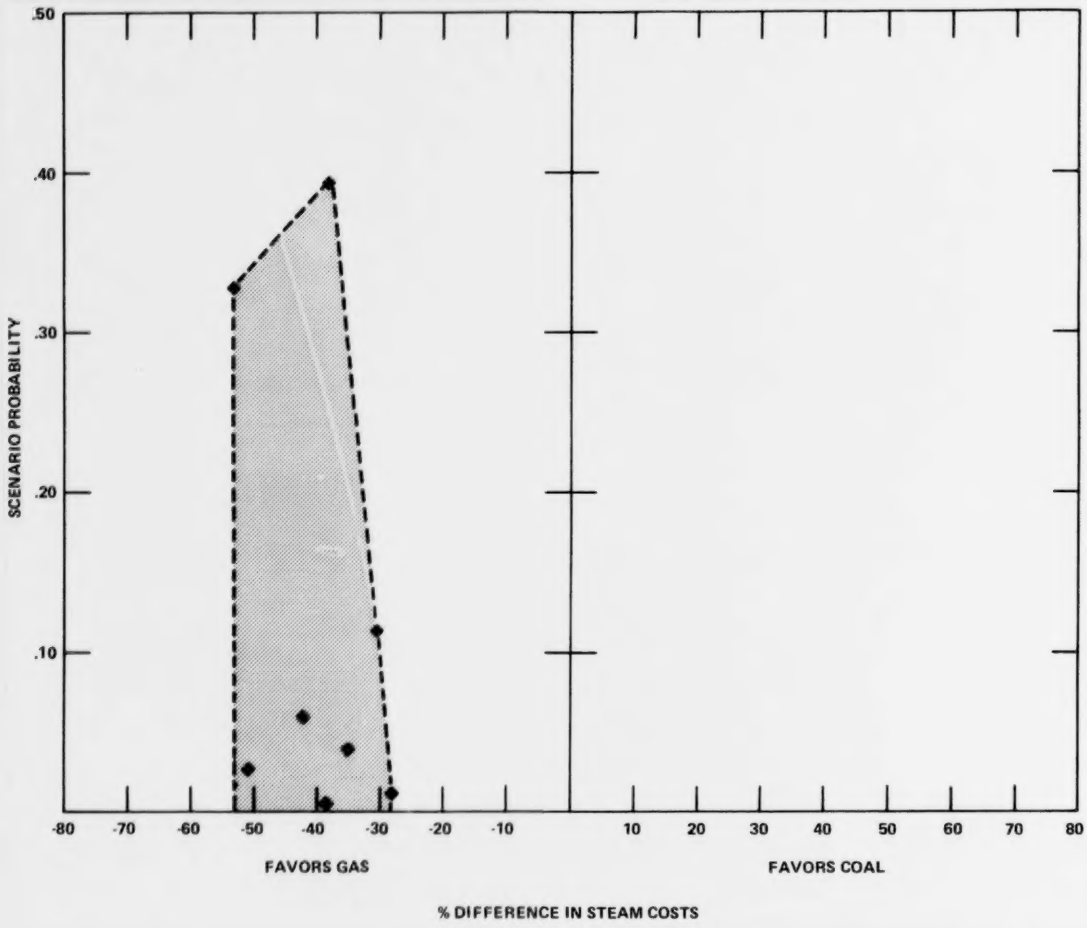

Figure 45. Comparative steam costs as a function of scenario probability: equipment manufacture/Gulf Coast (combined score = -43.0).

over future gas supplies and prices, and a more favorable outlook with respect to coal. Nonetheless, there is a strong discouragement, as evidenced by the aggregate score, to replace an existing gas or oil boiler with one capable of burning coal. As long as boiler size and load factors are small, fuel choice decisions will be somewhat insensitive to differences in fuel price or availability.

Food Processing - Great Plains--

Fuel choice decisions in the food processing industries are expected to be quite similar to those of the equipment manufacturing industries. Of course, it is much more difficult to generalize about the food industry because it is such a heterogeneous industrial grouping. Nonetheless, boiler

TABLE 56. STEAM COST COMPARISONS FOR GREAT LAKES EQUIPMENT MANUFACTURING INDUSTRY

Boiler Size: 50,000 lb/hr
Load Factor: 35%

	Coal		Natural gas			
Annualized capital cost ($ x 10^3/yr)	1929		489			
Annualized O&M cost ($ x 10^3/yr)	462		147			
Fuel cost ($/$10^6$ Btu)	High 2.92	Low 1.96	High 8.07		Low 5.14	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($ x 10^3/yr)	631	424	1768	1707	1313	1024
Total energy cost ($ x 10^3/yr)	3022	2815	2404	2343	1949	1660
Steam cost ($/$10^3$ lb steam)	19.71	18.36	16.68	15.28	12.71	10.83

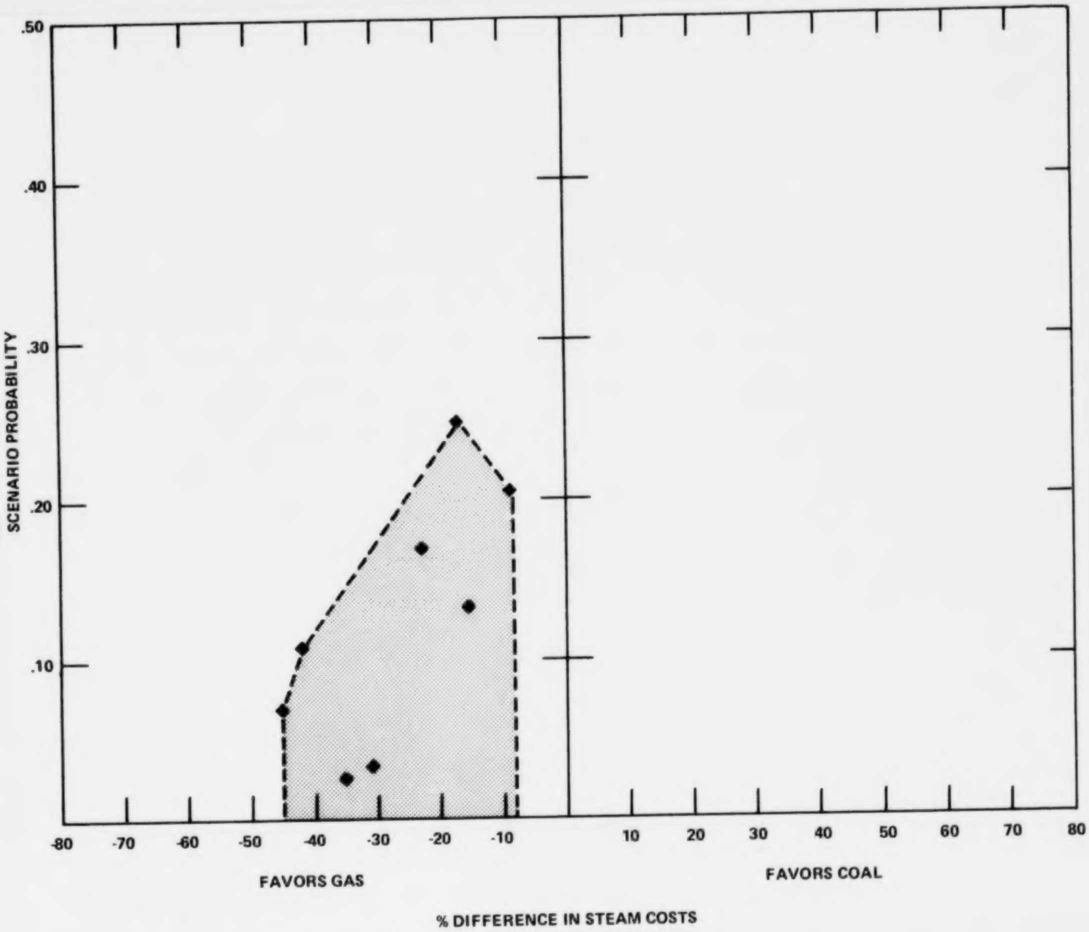

Figure 46. Comparative steam costs as a function of scenario probability: equipment manufacture/Great Lakes (combined score = -21.6).

sizes are typically small, load factors are low, energy costs do not comprise a significant portion of total operating costs, and capital availability may pose a serious constraint. The results of the fuel choice decision analysis, displayed in Table 57 and Figure 47, are similar to those for equipment manufacturing firms located in the Great Lakes. The probabilities suggest that gas will remain the most economical alternative. Unlike small Gulf Coast manufacturing industries, however, the expected benefits of continuing to use gas are less certain (the highest scenario probability is only 0.270) and are extended across a wide range of possible values. Both the heterogeneous nature of the food processing industry and the pronounced regional dispersion of food processing plants indicate that a greater number of individual food plant operators might view coal as a cost-effective alternative than would equipment manufacturing operators.

TABLE 57. STEAM COST COMPARISONS FOR GREAT PLAINS FOOD PROCESSING INDUSTRY

Boiler Size: 50,000 lb/hr
Load Factor: 45%

	Coal		Natural gas			
Annualized capital cost ($\$ \times 10^3$/yr)	1929		489			
Annualized O&M cost ($\$ \times 10^3$/yr)	498		148			
Fuel cost ($\$/10^6$ Btu)	High 2.92	Low 2.31	High 6.31		Low 4.02	
			Low Availability	High Availability	Low Availability	High Availability
Annualized fuel cost ($\$ \times 10^3$/yr)	811	642	1954	1716	1539	1093
Total energy cost ($\$ \times 10^3$/yr)	3238	3069	2591	2353	2176	1730
Steam cost ($\$/10^3$ lb Steam)	16.43	15.55	13.15	11.94	11.04	8.78

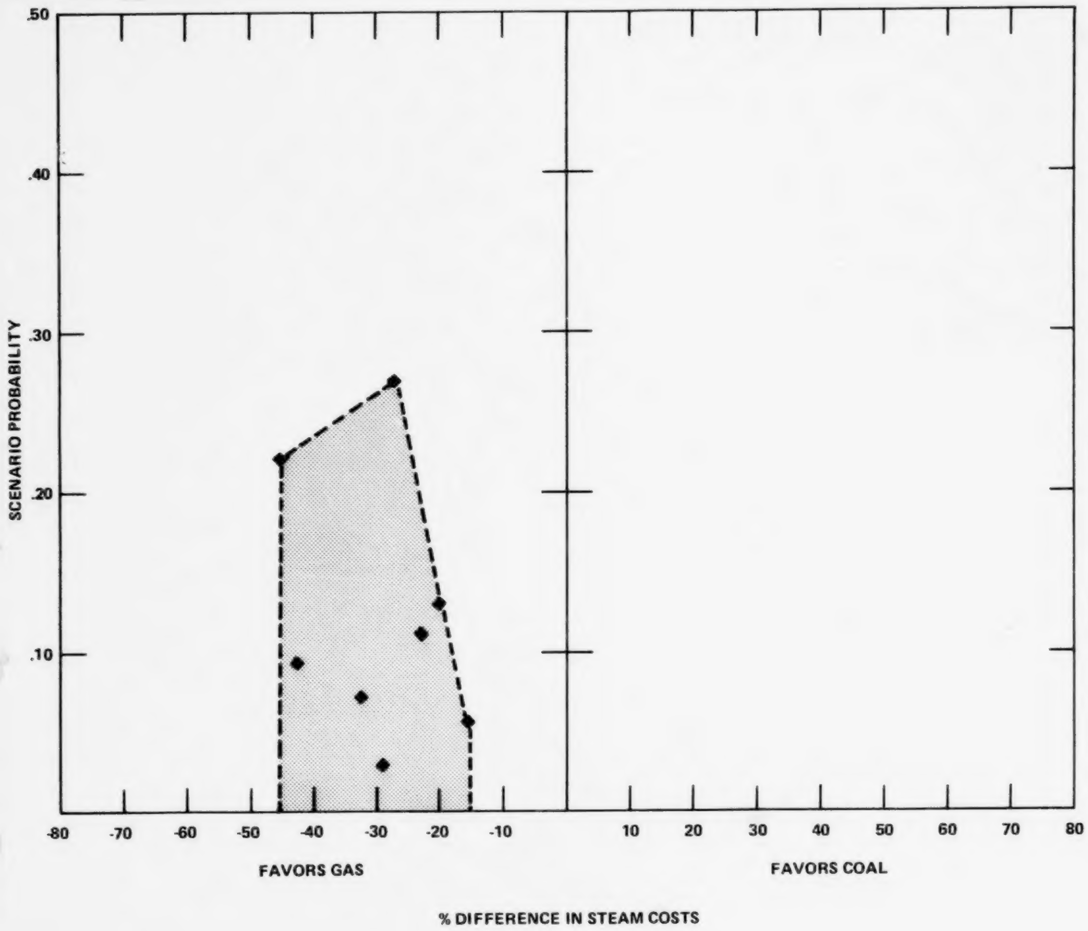

Figure 47. Comparative steam costs as a function of scenario probability: food processing/Great Plains (combined score = -31.5).

CONCLUSIONS

The Outlook by Region and Industry

Although the decision whether or not to burn coal can be accurately evaluated only at a site-specific level, a few generalizations can be drawn from the preceding analysis. As was readily apparent in the sensitivity tests, coal utilization is most likely to be cost-effective in large boilers, operating at high rates of capacity utilization, in energy-intensive industries where large capital investments to reduce operating costs can be economically justified. On the other hand, comparative steam costs may not always reflect accurately the full range of economic ramifications that a change from gas or oil to coal might entail.

The industry- and regional-sensitive fuel choice decision analyses allow more specific conclusions to be drawn. All things considered, the chemical industry is the industry most likely to change over to coal. The energy-intensiveness of most chemical plants provides a clear incentive to pursue a least-cost energy strategy. Boiler size and utilization rates, although moderate, are above the threshold point below which coal use is nearly precluded on economic grounds. Finally, the chemical industry expects a high growth rate during the coming decades; this will enable plants to relocate closer to coal resources. For the petroleum industry, favorable economics may be outweighed by constraints arising from plant siting patterns. Use of coal within the steel industry is certainly cost-effective, but current capital constraints within the industry and air quality considerations will combine to delay a conversion to coal. Boiler replacement will be given serious consideration in the primary aluminum industry as rising prices for gas and oil increase production costs. Ensuring a reliable supply to plants located in the Gulf Coast does remain a formidable obstacle, however, and unless coal transportation costs stabilize, plant operators in that region will be hesitant to change fuels. Much greater incentives will be required to stimulate the use of coal in small, less energy-intensive manufacturing plants. For these firms, the capital costs of boiler replacement projects are far too high to justify investing a limited amount of available capital in non-critical operations.

From a wider perspective, regional differences appear to be a determining factor in fuel choice decisions for large, energy-intensive firms. Beyond a certain scale, fuel cost differences tend to dictate which fuel and technology options offer the best long-term benefits. In contrast, smaller and less energy-intensive firms operate on a scale at which fuel costs are of less concern, and as a result, fuel choice decisions are relatively insensitive to regional differences. At present, the existing policies and programs to encourage greater coal in the industrial sector fail to address the key variables affecting fuel choice decisions in this smaller-scale segment of the industrial economy. This failure arises from the fact that existing programs are focused on costs rather than on risks. Except for the largest, most energy-intensive firms, the risks inherent in a changeover to coal are of as great concern as, perhaps greater than, the final delivered cost of steam. These risks include infrastructural instability, the relative price and availability of coal over the long term, regulatory uncertainty, a lack of technical expertise in coal technology, maintaining the pace of capital formation, and opportunities foregone in changing to coal.

It could also be argued that, even in the case of costs, existing policies do not represent the most effective strategy. For example, if the national purpose is to encourage a rapid conversion to coal, it would be more cost-effective to provide tax incentives, that would decrease rather than increase or remain unchanged with time (16). Such a strategy is analogous to the standard business practice of offering sales discounts for a limited period only. Even so, tax credits are not necessarily the best tactic for mitigating the high capital cost of changing to coal. Accelerated depreciation or government-sponsored low interest loans would probably be more effective in overcoming the constraints imposed by the magnitude of the capital investment required, especially for smaller firms.

Industry Responses

The preceding discussion and analysis is predicated upon probabilistic outcomes of hypothetical boiler replacement decisions by various industries. Legal requirements codified in the Fuel Use Act (FUA) were not taken into account; differential steam costs were the only determinant considered. Under the influence of the Fuel Use Act, however, fuel/technology decisions become divorced somewhat from pure economic rationality.

It is in the process of gaining an exemption from the Act's provisions that complications arise. Exemptions on economic grounds can be gained only through demonstrating that the cost of using coal "does not substantially exceed" the cost of using imported petroleum. An acceptable definition of a "substantial" increase has, as yet, not been devised. It is equally unclear whether the price of natural gas will ever reach parity with imported petroleum. Thus, the relative costs of using natural gas are essentially excluded from consideration. Moreover, the basis of cost differences is implicitly defined as the cost of steam. As a result, the economic impact on industrial firms of paying much higher capital costs for coal technologies and other opportunity costs of fuel switching--dedication of land to coal storage and waste disposal, for instance--will not be measured. The perspectives of the plant manager or corporate officer about the costs of fuel conversion are likely to be different from the perspectives of regulatory agencies. Related issues, such as what constitutes an "adequate and reliable" supply of coal, may have a much different meaning to decision-makers in industry than they will to government policy-makers. The central point is that some industrial firms, while failing to gain exemptions from the FUA, may still determine that conversion to coal is not in the best interest of maintaining their economic integrity. The potential impacts of such conflict should be considered.

For existing plants where operators desire to replace an obsolete boiler or to increase steam plant capacity, a number of options would be available. First, old gas or oil boilers that would normally be replaced could be maintained. Older boilers are generally less efficient than those with new designs. The net effect, therefore, might be to use more gas or oil than would be used if the unit were replaced. This strategy may also have a negative effect upon steam plant reliability. Second, in some instances, the mandate of the FUA could be circumvented by installing small boilers to replace an existing larger unit. Third, an existing boiler could be retired, yet not replaced. Such a response could either lower steam plant reliability, decrease a plant's ability to efficiently respond to fluctuating loads, or result in cutbacks in production. In some older plants, cessation of operations entirely may be more economical than making a large capital investment in a coal-capable steam plant.

For new "grassroots" manufacturing plants, the use of coal generally presents a more favorable option. New plants can be constructed in proximity to coal supplies and designed in a manner that accommodates the space demands of coal-fired steam plants. Nonetheless, continued uncertainty over the future price and availability of coal to small users, apprehension over environmental regulations, as well as the capital costs of coal-capable equipment, will continue to discourage coal use. In some cases, the necessity of building new plants near coal reserves will conflict with other plant siting considerations--proximity to markets, labor, raw materials, and transportation. To avoid conflicting environmental and energy regulations, some plants may substitute a greater amount of direct-fired heat for steam. Such substitutions would, in most cases, result in efficiency losses and thus would have the net effect of increasing gas or oil consumption. A final concern is the probability that some energy-intensive companies may locate a greater number of new plants overseas. The potential impacts on employment and on balance of payments should not be overlooked.

It is, of course, impossible to accurately predict the full range of potential economic ramifications arising from policies mandating the use of coal in industrial boilers. During the interview campaign conducted as part of this study, however, many of the concerns and possible reponses outlined above were acknowledged by industry spokesmen. It does not appear that present energy policies, as exemplified by the Fuel Use Act, take full account of their possible economic, environmental, and energy implications. These implications are discussed further in the following chapter.

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CHAPTER 11

CONCLUSIONS

The historical imperatives that shaped the Nation's industrial development have given rise to a configuration of technical systems which is not particularly amenable to a rapid shift to coal. Industries, for the most part, are concentrated in a few geographical areas. Such concentration has led to restrictions on the amount of space available to individual manufacturing plants and resulted in a close proximity between industries and areas of high population density. The concentration of industries and populations, with the concomitant concentration of transportation and commercial support systems, has caused the quality of the air in these areas to seriously degrade. Only recently has a public commitment to restore the quality of the environment in heavily industrialized and urbanized regions been made, and translated into specific policy actions. In the last twenty-five years, much of the progress that has been made has arisen from a shift away from coal to cleaner fuels. Thus, a return to the widespread utilization of coal raises a clear contradiction between environmental and energy goals. And, as shown in this report, even the application of advanced pollution control mechanisms will not, in many cases, be sufficient to allow continued improvements in air quality to be made.

Other constraints to an increased use of coal in industrial boilers can be traced to historical factors as well. The progressive movement to small, packaged, and low capital cost boilers, places severe restrictions on the technical capability of existing equipment to use alternative fuels, especially coal. Changes in mining technology, policy initiatives designed to protect the health and safety of miners and to minimize environmental damage from mining operations, gradual changes in coal marketing and management practices, as well as deficiencies in existing transportation systems, cast serious doubts on the adequacy of the supply infrastructure to support a widespread shift to coal in industrial boilers.

Together, all of the factors mentioned above combine to place a substantial cost penalty on the use of coal. Costs of control technology, waste disposal, land, boiler replacement, and transportation, are often more than enough to offset the rapid increases in the price of natural gas and oil. More importantly, the capital intensiveness of coal technologies can raise a host of financial problems to industrial firms.

Each of these constraints appears to be rather intractable. To the degree that they arise from long-term historical trends, from conflicts with other public goals, and from imperatives of our economic system, the full spectrum of potential policy initiatives designed to provide a near term, and widespread, shift to coal in industrial boilers will be severly compromised. Thus, a 6 Q level of coal use in industrial boilers by the year 2000 does not appear to be technically, environmentally, economically, or politically feasible.

APPENDIX A

SUMMARY OF INTERVIEW PROGRAMS

Interviews focused on the Great Lakes, Appalachia, and Gulf Coast regions, and some information for other regions was gathered in order to highlight and contrast important points. The survey included respondents from the chemicals, primary metals, petroleum refining, food processing, and automobile manufacturing industries. Two important energy consuming sectors, paper and stone/clay/glass, were omitted: paper because very few plants are located in the study regions, and stone/clay/glass because boiler use is an insignificant portion of total energy use. Automobile manufacturing is included to illustrate the difficulties coal use entails for industries that are less energy intensive. A special section is presented at the end that details the problems coal use entails for small producers in all sectors.

INTERVIEW RESULTS

Chemicals

Chemical industry use of coal may well increase substantially as rising oil and natural gas prices stimulate an evaluation of other energy sources. Coal is, at present, a relatively unimportant fuel, accounting for less than seven percent of total sector energy use. The interviews revealed, however, that, as the leading industrial energy user, the industry is extremely sensitive to price and supply uncertainties and is actively considering alternatives to petroleum for energy and feedstock requirements.

Several factors will influence the acceptance of coal as a boiler fuel by the chemical industry. Favoring coal use are a number of economic considerations, including the high contribution of energy to total costs, the economies of scale and ready access to capital exhibited by large companies, and technical and managerial expertise in processes similar to those in advanced coal technologies. On the other hand, perceived adequate supplies of natural gas, overseas expansion opportunities, transportation and other logistical problems, and air quality regulations inhibit future growth in coal consumption.

Interviews were conducted with a variety of companies in the Gulf Coast and Great Lakes regions. The results reported below, however, concentrate on organic chemical producers in the Gulf Coast states. Respondents in Pittsburgh were generally small producers of specialty chemicals for the steel industry and findings for them are presented in the "Small Producers" section.

Organic chemicals are the focus of the discussion as they account for over two-thirds of total output in the industry and anticipate rapid future growth. In addition, organic chemicals production is of special interest because of its extreme energy intensity and its close association with the petroleum refining industry.

Steam raising, though less important than feedstocks and direct fire heat, is an important use of energy in the chemical industry. In 1977, process steam and electricity generation were, respectively, 24.5 percent and 15.0 percent of total non-feedstock energy consumption. Process steam is used in a variety of chemical operations, and electricity is primarily a power source for pumps, compressors, and other equipment. Boilers are generally large (over 100,000 lb steam pressure/hr and, in some cases, several hundred thousand lb/hr), and may run at individual capacity factors of 95 percent or better. System load factors can approach 70 percent.

All firms interviewed produced their total process steam requirement, although two cases were noted in which companies planned to begin purchasing steam from an electric utility. For electricity generation, small plants have disadvantageous economies of scale and generally rely on utility sources. Some large firms engage in self-generation for up to 50 percent of their needs, but even these depend on utilities for the remainder of their requirement and for backup capacity. Cogenerating process steam and electricity is a practice favored by the large boilers, high utilization rates, and compatible steam requirements found at many plants. In order to take advantage of economies of scale, chemical plants are often very large. Large boilers are employed and these allow for relatively cheap unit costs for electricity production. In addition, continuous utilization of boilers for process steam production is consistent with the continuous operation required for efficient electricity generation. Finally, many chemical processes are dependent on high pressure (over 200 psi) steam, which is also suitable for electricity generation.

Natural gas, oil, and by-product gases from petroleum feedstocks account for 80 percent of total industry energy use, but boiler fuels displayed considerable regional variation. Along the Gulf Coast most boilers fire process gas, natural gas, or oil, and there has been a recent trend away from oil.

In the Great Lakes and Appalachia regions coal plays a much larger role, although air quality considerations have precipitated some switching to other fuels. One plant in Pittsburgh has shifted to natural gas and another company in Michigan has contracted to buy process steam from a nearby utility's soon-to-be-constructed nuclear generating station, for its exceptionally centralized facility. For the future, coal will probably make a significant contribution in the north, while opinions are mixed in the Gulf Coast. Some companies state that they will never convert, some have converted (and regret it), some have firm intentions to do so, and some are undecided at present.

In all regions, by-product gases (that is, waste hydrocarbons from feedstocks) are a significant boiler fuel, accounting for ten to forty percent of total requirements. Since process gas is essentially a free fuel, there is little incentive to replace it with coal unless it is of sufficient Btu content to warrant selling it to other companies.

There are, however, compelling reasons for replacing oil and natural gas with coal, the most prominent of which is the high absolute and proportional contributions of energy to total product costs. As noted, the industry consumes tremendous amounts of energy for a number of purposes, including steam generation, and in some firms, energy costs are over 50 percent of production costs. Because they are so pronounced, energy costs have weighed heavily in system design and capital investment decisions. In the past, plants were built to accommodate oil and natural gas, the purchased fuels offering the lowest overall energy costs. As petroleum becomes more expensive, however, attention is increasingly given to the possibility of investing the capital necessary to make use of cheaper fuels like coal.

Using coal, of course, implies substantial capital investment in combustion, pollution control, and ancillary equipment. The heavy front-end costs associated with these technologies are generally acceptable. Large plants and economies of scale have been the rule for decades in the industry, and any investment that will reduce energy costs per unit of output will not be discouraged solely on the basis of its capital requirements. In addition, investors perceive the industry as healthy, and companies usually have access to sufficient debt and equity capital to undertake projects that have been determined to be economic.

One case was discovered, however, in which a very large firm opted out of a coal conversion project that would have been clearly cost effective because of the adverse effect that diverting funds from developing new products and more efficient processes would have had on its market share.

Increased coal use in the chemical industry is favored by other factors as well. The industry expanded output by 12 percent in 1979 and, as in recent years, is expected to grow at a rate well above that of the economy as a whole. Growth means the industry will continue to attract investments from other sections of the economy and that deployment of coal technologies will not be constrained by a shortage of capital. Expansion will require new facilities, the boilers for which will very likely be coal-fired. Some of the impact of continued growth will be dulled by expansion overseas, especially in developing countries where materials, labor, and environmental constraints are less binding. This loss, however, will be partially offset by investment by foreign chemical companies in this country. In 1979, this was the leading category of foreign investment in the United States.

The compatibility of coal technologies with the experience, expertise, and needs of the chemical industry also favors increased utilization. In contrast to other sectors, where the chemical process, materials handling, and waste disposal aspects of coal technologies like scrubbers, fluidized-bed combustion, and gasification are a formidable obstacle, the chemical industry is familiar with these procedures. For years companies have routinely "scrubbed" out impurities, changed molecular structures, and disposed of unwanted by-products. The companies will gain additional experience in coal technologies as they experiment with ways of substituting coal-derived products for feedstocks currently supplied by oil and natural gas. Some companies have begun work on new coal technologies. One company reported development work on a gasification, combined cycle, cogeneration technology which it hopes to use in its own large plants and to market to other companies. Because of their competence with these more advanced and efficient technologies, chemical companies exhibited little interest in dealing with perceived costs, inefficiencies, and other problems associated with scrubbers.

Despite these apparent advantages, there are reasons why many chemical companies are reluctant to increase coal use for either existing or new facilities. Some are industry-wide, while others indicate regional sensitivity. One industry-wide concern is the status of existing investments. Old, inefficient boilers that were already scheduled for replacement are more likely to be converted to coal than new, efficient units that have not been fully amortized. From the limited number of interviews, the preliminary impression is that the industry has experienced fairly steady growth and that plant ages are fairly equally distributed between zero and thirty years.

Another cost of conversion relates to the disruptive effect shifting to coal can have on plant operation. As noted in Chapter 5, "coal conversion" is a misnomer because major, and often inconvenient, changes in plant configuration are necessary to accommodate the new boiler, space, and equipment demands of a coal-fired energy system. While all of these will undoubtedly cause some inconvenience at chemical plants, fewer complaints in this regard were noted in the chemical industry than in other industries.

Another argument against conversion to coal that was encountered in all regions of the country, but perhaps most strongly in Houston, is that adequate supplies of natural gas would be available in the future at affordable prices. Further, even if conventional supplies should give out, there is widespread belief that new sources like Mexican imports, liquid natural gas imports, and gas from coal will all be available. While perhaps not as unshakable as in Houston, there was in Pittsburgh, as well, the perception that gas would still be the most economical fuel in the future. There are, of course, companies in all regions that acknowledge the eventual price and supply problems with natural gas, but many of these feel they have until the late 1990s before coal conversion becomes imperative. As for new plants, those respondents planning expansion in this country indicated coal to be the fuel of choice. Extensive investigation of FBC was reported.

In addition to these industry-wide concerns, there are a number of regional issues that will affect the level of coal utilization by chemical companies. The two most important are air quality and transportation costs. Air quality is particularly problematic in the Pittsburgh and Houston areas, and this affects fuel choices in two ways. The first is through the costs that must be incurred for the pollution control equipment necessary to achieve acceptable emissions levels. The second is that permitting and siting procedures make it very uncertain whether new or existing plants in these regions will be allowed to burn coal at all. The delay and expense associated with this uncertainty will be an important factor in technology and fuel decisions.

The second regionally specific constraint on burning coal is the very high coal transportation rates in the Gulf Coast area. Costs are evidently so high that few companies can justify coal economically, even in the face of rising natural gas prices. One company converted its plant in the Texas Panhandle to coal in 1973, but has been losing money ever since owing to the rapid escalation in freight rates. The company has no plans to convert its three plants in the Houston area to coal. The one company with any intent to consider coal for its Houston operation may use nearby lignite, of which it owns plentiful reserves, for minemouth gasification. Transportation requirements could pose a serious industry-wide constraint to direct coal use, however, since 60 percent of present chemical industry capacity is located in the Gulf Coast (CTA Region VI), 40 percent in Texas alone.

Primary Metals

Primary metals is the second largest energy consuming sector, using 4.7 Q in 1977 in a variety of applications including materials reduction, direct fire processes, process steam raising, and electricity generation. Industry wide, energy costs are a substantial portion of total product costs, and steam boilers account for sixteen percent of energy consumption. There are, however, significant regional and historical differences in fuel use patterns, technology development, and current and projected markets among ferrous and non-ferrous metals producers; these sectors are treated separately below. Because steel and aluminum account for over 90 percent of the sectoral energy use, they are the focus of the discussion.

Steel--

The interviews revealed an intense conflict between the steel industry's willingness and ability to burn coal under boilers and air quality regulations.

For over a century coal was a major energy source in the industry, and there developed an extensive supply infrastructure, capital stock, and technical expertise to make it an economical and convenient fuel. While primary metals still account for two-thirds of industrial coal use, environmental regulations prompted a shift in the 1960s to cleaner fuels. The tensions between the recent awareness of environmental values and the industry's economic interests were intensified in the 1970s with the appearance of stricter air quality regulations, a steep rise in oil and natural gas prices, and the stated national goal of substituting coal for less abundant fuels where possible. The following section describes boiler use patterns in the steel industry and outlines 'key fuel and technology decisions made in response to these changing circumstances, with particular attention to the economic rationale and implications for efficient plant operation of these choices. It also addresses major sources of contention among industry, environmental, and energy goals, and prospects for their resolution.

Boilers are used in the steel industry to raise pressure steam (over 200 psi) for process applications and electricity generation. Process applications include turbo-blowers, chemical treatment works, and other apparatus, and electricity is used for induction heating and electric arc furnaces and miscellaneous drives. All companies produce their total requirement of process steam; self-generated electricity accounted for ten percent of electricity needs in the highest case encountered.

For the large producers, a typical plant contains several large boilers of at least 100,000 lb/hr and often 300,000 to 500,000 lb/hr, which are used continuously. There are also small (less than 100,000 lb/hr) package boilers, for meeting daily and seasonal peaks. The small boilers do not provide backup capacity for "baseload" units, and there is, evidently, little redundancy at these plants. The large boilers are often of Korean War vintage and have large fire boxes designed to accommodate low Btu fuels like coal and by-product gases. In response to environmental restrictions on coal use, these boilers have been modified slightly and are now capable of firing oil and natural gas as well. The small boilers were originally designed for oil and natural gas and cannot be modified to burn lower heat value fuels.

Energy is a significant cost factor in the steel industry, and there have been economic incentives for making capital expenditures that allow reduction of overall energy costs by burning inexpensive fuels. Large, field-erected boilers capable of firing low heat value fuels are typical, and, in order to spread their capital costs over as many units of output as possible, utilization rates are high. For the small boilers, the economic strategy is to accept the higher fuel costs of oil and natural gas in order to conserve on capital outlays.

Boiler fuel choice is closely associated with overall design of the steel-making facility. At integrated plants, that is, those that make both coke and steel, there are several options depending on the iron reduction process employed. At plants built up to the early sixties, where blast furnaces are employed, the fuels of choice are coke oven gas (450-600x10^6 Btu/cf) and blast furnace gas (70-100x10^6 Btu/cf). These process gases are by-products of steel making and except for the costs of piping and gas cleanup--coke oven gas is sulfur free when it leaves the facility--are a free fuel to the company. Coke oven gas can be economically shipped moderate distances (up to, say, 50 miles); blast furnace gas must be used on the premises where it is produced. By-product gas production is, however, ultimately limited and even at fully integrated plants, other fuels must be considered. Also, a number of companies operate dispersed facilities where coke oven gas is not available and they, too, must rely on other energy sources. For both these cases, coal has traditionally been the preferred fuel.

Plants have been designed, sited, and built to accommodate these fuels. Process gas pipelines, railroad sidings and barge terminals, unloading facilities, handling equipment, and storage facilities are in place. Generations of expertise, which, in contrast to many industries, have continued through to this day to minimize the convenience and logistics problems often associated with coal, make it one of the industry's preferred fuels. In addition, many plants in the Great Lakes area are close to coal deposits and transportation and supply problems are rare. In the Pittsburgh area, for example, some companies reported that their coal was hauled by truck from less than 50 miles away, although barge and rail transport account for significant quantities.

Until the early sixties, process gas was used for over half (at least 60 percent and in some cases 90 percent) of boiler fuel, and coal accounted for most of the remainder. Environmental regulations and other considerations, however, have greatly reduced the portion of boiler fuel supplied by process gas and coal, and oil and natural gas use has increased substantially. Coke oven gas output has declined as coke production dropped 25 percent from 1973 to 1979, owing to environmental restrictions and cheaper imports. Many coke ovens (at least 30 percent) in the U.S. are over 25 years old and are not worth the investment required to bring them up to the standards required by recent environmental regulations. Capital constraints in the industry have forced some companies to shut down coking operations and purchase their supplies from outside. In addition, blast furnace gas output has also declined as old furnaces are replaced with electric arc melting furnaces.

These trends in the availability of process gas have enhanced the role of coal as a candidate boiler fuel in the steel industry. Given the declining production of by-product gases and the rising costs of other fossil fuels, coal might be expected to grow from the 30 to 40 percent of total boiler fuel it comprised in the 1950s. In the companies contacted, however, coal amounts to 0 to 20 percent of boiler fuel. The reason for this counter-intuitive shift is that growing concern over the air quality impacts of coal use in the densely populated cities of the Great Lakes region has prompted restrictions on coal use. These laws have led the steel companies to consider a number of strategies for meeting their boiler fuel needs.

Several alternative strategies have been adopted in the steel industry. In no instance were conventional flue gas desulfurization systems employed as a solution because of their cost, reliability, space disadvantages, and solid waste. Rather, the emphasis has been on shifting fuels. In fully integrated plants, the strategy has been to control particulate emissions with electrostatic precipitators and to increase the amount of by-product gas burned to reduce sulfur emissions. Since process gases are essentially sulfur-free when they enter the boiler, increasing their use frees up some increment for uncontrolled coal emissions. At plants where sufficient by-product gases are not available, the company must switch to low-sulfur coal, to oil, or natural gas. Low-sulfur coal prices are comparatively high, because of increased demand and greater transportation costs--most low-sulfur coal in the Pittsburgh area comes from Kentucky, not from local mines. Gas and oil are also expensive and companies restrict their use as much as possible.

One disadvantage of coal as a boiler fuel that is often cited in the literature is the unreliability of supply, as a result of weather and labor problems. In the steel industry in the Pittsburgh area and much of the Great Lakes region, this is not a major problem because high sulfur coal comes from local sources and the distance between mining and consumption is so short that weather-related problems and transportation problems generally do not occur. For barge transported low sulfur coal, there can be difficulties in winter. However, in regard to both transportation and labor strikes, some respondents indicated that they were better off now than in the early sixties, because of the present capability to fire alternative fuels. Many boilers were originally designed with multi-fuel capabilities such as blast furnace gas, coke oven gas, and coal. With the introduction of the air quality constraints, these received capability for additional fuels such as oil and natural gas. Given such fuel flexibility, steel plants can survive a lengthy coal strike, albeit at the economic cost incurred by using more more expensive fuels. Most coal is purchased on short-term (one year) renewable contracts, and there was no indication from the industry that it would encounter shortages on the spot market in the future.

Were it not for the air quality constraints, then, the industry would quickly shift from oil and natural gas to coal as fuel for large boilers. The technical obstacles and capital expenditures that hobble coal conversion in other sectors are rare in the steel industry, in part because much of the capital stock predates the conversion to natural gas and oil which occurred in other industries in the sixties and seventies. Coal-capable boilers and coal handling equipment are generally still in place, although some companies did report that coal storage space has been put to other uses. In addition, both the technical expertise and sentiment for using coal in steel plants are still alive and would assist in any reconversion effort.

One escape from the quandry is gradually to relocate the steel industry in regions where the air quality constraints are not as binding. While the steel industry is beginning to break out of its pattern of concentration in a few states along the Great Lakes by building new plants in the midwest, west, and south, massive relocation is unlikely. In addition to questions of logistics, raw materials, and supplies, there is the over-arching issue of capital formation. The industry is severely capital-constrained and investments will be made at strategic junctures in existing operations rather than in building a new industry in a different location. While the industry's worst days may be behind it--a 2.5 percent annual growth rate is projected to 1983--capital will continue to remain in short supply.

A second broad alternative is investment in advanced coal technologies at existing sites. Industry sources were, however, cautious about the potential for coal combustion processes such as fluidized-bed and low-Btu gasification for a number of reasons. In the first place, the industry faces a severe capital constraint in its steel-making operations and little serious consideration is given to building many new facilities or replacing existing boilers. In the few cases where replacement is imminent, FBC boilers would not be installed because they lack the demonstrated reliability necessary in an industry where redundant capacity is the exception. One respondent pointed out that gasification might be considered because of the industry's extensive experience in gasification in its coking and steel-making processes. Another company is now cooperating with the Department of Energy in demonstrating a low-Btu gasifier to generate boiler fuel to replace oil and natural gas.

Aluminum--

In the aluminum industry, coal is a serious candidate fuel for new boiler capacity, but respondents emphasized it is only one of several alternatives under consideration. The range of options for minimizing energy and end-product costs is enhanced by several characteristics of the industry, including its geographic dispersion, heavy reliance on electricity, generally rural base, and substantial investment in a variety of energy resources. As opposed to the steel industry, which is highly concentrated along the Great Lakes, primary aluminum production is spread over thirteen states, ten of which are in the Gulf Coast, Appalachia, and Great Lakes regions.*

As a result, several energy sources are available, among them natural gas, hydropower, and coal. In addition, as the industry relies heavily on electrolytic and electrostatic conversion processes, there is the possibility of using even greater amounts of purchased electricity. Primary aluminum plants tend to be located in rural areas, so air quality is less of a constraint to coal use than in other industries. Finally, since energy is such a significant portion of total costs, many of the major companies have invested in coal and natural gas reserves, and maintained rights to potential hydroelectric sites.

Any of these fuels might be used in quantity because of the large energy requirements in primary aluminum plants. The industry is very energy intensive, using, for example, three times the Btus per unit output of the steel industry. Of the total energy consumption, boilers account for 40 to 80 percent, depending on how much electricity is self-generated, and there may be significant additions to capacity in the future as the industry is now running at about 95 percent of capacity.

Steam boilers play a major role in the two phases of primary aluminum production, ore separation, and metal smelting. Ore separation, a steam-based process, constitutes 10 to 15 percent of total energy use. Here large boilers (over 1,000,000 lb/hr in one case) raise steam to convert bauxite to alumina. Since over 75 percent of all bauxite is imported from the Carribean and South America, separation plants are located along the Gulf Coast in order to defray the expense of moving this bulky ore inland. Natural gas, with an oil backup, has been the economical boiler fuel.

In the smelting stage, various electricity and steam-based processes are used to convert alumina to aluminum. Here the remaining 85 to 90 percent of total energy is consumed, approximately 70 percent as electricity and 30 percent as steam. Boilers at smelting facilities are also large (over 200,000 lb/hr) and utilization rates are high, usually 85 to 98 percent on an individual boiler basis. All companies produce their own steam and a 25 percent redundant capacity is maintained for these boilers. Only those firms with requirements over 100 MW would consider generating their own electricity, and even some of the heavy consumers elect to rely on utilities. Companies that produce their own electricity purchase some power from utilities and rely on utilities for backup capacity. Because it is economical, under certain circumstances, to ship alumina considerable distances, smelting plants are located throughout the Gulf Coast, Appalachia, and Great Lakes regions, and a variety of boiler fuels are used.

Energy costs are a major contributor to total costs, and all companies select the combination of capital and variable costs that yields the lowest energy cost per unit output and is most consistent with other corporate goals. For process steam, regional fuel prices and availability determine the choice. In the Gulf Coast region, cheap natural gas is procured on long term contracts as boiler fuel. In the regions to the north, higher capital investments in boilers are required to take advantage of coal that is regionally abundant and inexpensive, but lower in heat value. For electricity needs, two strategies are followed, with little apparent regional correlation. The first is self-generation, and the choices here are the fuel and technology options outlined above and the possibility of using hydropower. The second is to purchase electricity from the local utility. The advantage of self-generation is reliability, once primary and secondary fuel supplies are assured, the supply of electricity is relatively stable. Its disadvantages relate to its costs. The companies are not capable of the economies of scale of the utilities and, hence, unit costs are higher. In addition, investing in electricity-generating capacity directs capital from other corporate needs. The advantage, conversely, of purchasing electricity is that it is both cheaper and conserves scarce capital resources. Its disadvantage is it exposes the firm to curtailments imposed by the power company. These are likely to have more severe effects than fuel shortages because an alternative electricity supply is harder to find than a backup source of fuel.

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*Issues related to procedures in the Pacific Northwest and Rocky Mountain regions are treated only peripherally in this discussion.

In pursuing all of these strategies, primary aluminum plants have traditionally been sited near sources of cheap, plentiful, and reliable energy. Many plants are decades old and reflect historical energy availability patterns. Concentrations of facilities in the Tennessee Valley and the Pacific Northwest reflect the availabiltiy of abundant hydropower, while those on the Gulf Coast use cheap supplies of natural gas. Plants in northern Appalachia and the Great Lakes regions have been traditionally fired by coal. Changing energy supply and technology, however, will alter these patterns, especially as new plants are built to replace retired facilities and to meet additional demand.

Several factors are considered when a company selects fuel and technology for new boiler capacity. The two most prominent are the price and availability of traditional energy sources and the technical and organizational problems related to shifting fuels. Hydroelectric power for smelting operations is still viable in a few cases, but sites are not as plentiful as they were in the past.

Industry officials are confident that plentiful supplies of natural gas exist and that forcing a switch to other fuels serves no public or private purpose. Many respondents suggested there was at least a forty-year supply of gas available and that, in any event, their particular companies were supplied on non-interruptable service contracts, by company-owned resources, or by gas with assured supplies of fuel oil in case of a shortage.

The Fuel Use Act and rising gas prices, however, have forced the companies to consider coal as a boiler fuel for both existing and new plants. Reaction to coal is mixed. On one hand, there are a host of economic and operating disadvantages of coal use. These include higher capital costs, which are especially distasteful to companies attempting to conserve capital for other projects, and higher fuel costs resulting from escalating rail rates. Major operational problems are lack of experience and expertise with coal, inventory problems relating to space and possible supply interruptions, waste disposal costs, and delays owing to regulatory uncertainty.

Some companies, on the other hand, recognize the savings to be realized from coal use in new and replacement situations. Capital costs are much more acceptable for new boilers than for retrofit projects. Many companies acknowledged holding considerable coal reserves. Many respondents mentioned the in-house and nationwide shortage of coal technicians as a serious problem, but actions are being taken to correct this situation. Several companies are participating in government sponsored demonstration projects for advanced technologies such as fluidized bed, solvent refined coal, and coal gasification. Coal gasification was particularly appealing to one company because it would allow shifting to coal while maintaining existing gas-capable boilers. Scrubbers were universally condemned as costly, inefficient, unreliable, and fraught with solid waste problems.

Opportunities for coal use must be evaluated in the context of wider investment and technical options for aluminum producers. The industry is running at almost full capacity. Stung in the early seventies by serious overcapacity, and constrained recently by insufficient capital resources, most firms elected to forego investment in new facilities and reap record profits from high capacity use of existing plants. Demand is projected to grow 25 percent by 1983, but domestic capacity by only 10 percent. Investment in overseas capacity is an appealing alternative to a number of companies that are partners in joint ventures in Latin America and Australia. To the extent that expansion in domestic capacity is not forthcoming through the 1980s, coal use will increase only slightly in the industry as conversion is economical only in the few instances where boilers were scheduled for retirement in any event. On the other hand, one large firm is engaged in a five-year demonstration project to smelt aluminum ores with coal, much the way coal is used in steel industry blast furnaces. Should this technology prove feasible, direct coal use in the industry could rise dramatically in the late 1980s and 1990s, replacing much of current steam and electricity use.

Petroleum Refining

Petroleum industry respondents indicated that, while there are many short-term economic and technical issues to be resolved, prospects appear to be good for increased coal use at refineries over the long run. In the near future, several structural characteristics of the industry and site-specific difficulties will constrain substitution of coal for natural gas and oil. High capital costs and the necessity of writing off existing investments, long construction lead times, the concentration of refineries in areas with air quality problems, and a lack of experience and expertise with coal all discourage rapid conversion of current plants. Coal use is further constrained by site-specific conditions such as air quality regulations, solid waste disposal costs, space requirements, and uncertainties about transportation costs. In the long run, however, several factors may encourage a shift to coal. The two most important are continually rising prices of natural gas and oil and the eventual emergence of new technologies that will allow coal use with minimum modification of existing processes. Over time, as well, the industry will become more familiar with coal, capital expenditures for plant modification and construction will be required in any event, and construction lead times may be accommodated. The discussion below treats these short-term constraints and long-term opportunities, and describes which factors may allow conversion in the short run.

Petroleum refining is the third largest energy-consuming sector; it used 2.8 Q in 1977. Energy use is fairly intensive, accounting for 20 to 30 percent of total product costs when recent price hikes are taken into consideration. Energy costs, however, vary with product mix, and the diversity can be substantial as most large refineries are integrated with nearby chemical complexes. At present, boilers account for only 25 percent of total energy use, but this could rise to over 40 percent with the substitution of steam for direct flame in some applications. Boilers now raise steam for process applications and to generate electricity for pumps and compressors. The industry is concentrated in three geographic regions, the Gulf Coast, the mid-Atlantic states, and California; isolated plants are found throughout the country.

A series of steps are performed in a petroleum refinery to convert crude oil into gasoline, kerosene and middle distillates, chemical feedstocks, and residuals and by-products. Crude and secondary fractionating, performed by all refineries, are processes in which crude oil is heated to allow distillation of the various components. The first run produces ethane, methane, propane, and the like, while the second generates more refined products like gasoline. A third step, which only large refineries perform, is to restructure the molecules of valueless waste materials into useful products through cracking and other processes. Each of these steps creates by-product gases ("refinery gas"), which range from hydrogen (320 Btu/cf) to propane (2,100 Btu/cf). Both steam and direct flame are employed in these processes.

Boilers supply high pressure steam (200 to 1600 psi) for these processes. Steam consumption is substantial and boilers tend to be large. Most of those encountered were 100,000 lb/hr or more, with some rated at over 1,000,000 lb/hr. Utilization rates for large boilers are high, usually in the 85 to 90 percent range. Redundancy is achieved with supplemental boilers so that a typical plant might have four boilers, three of which would operate at any one time, yielding a system load factor of about 65 percent.

Boilers are fired by a variety of fuels. The several by-product gases mentioned above are the primary fuel at most plants, accounting for over 50 percent of total fuel consumption. In contrast to these gases, which are insensitive to plant location, supplemental fuels vary considerably by region. In the Gulf Coast region, natural gas is the fuel of choice, and fuel oil and residual oil are employed only as backup at most plants. In the mid-Atlantic states, the situation is reversed with oil as the primary and natural gas the secondary fuel. Most plants have multiple fuel capabilities; refinery gas, natural gas and oil are all high heat-value fuels, and are substitutable in existing boilers without problems.

As in other industries that are large users of energy, fuel costs are a cause for corporate concern. One strategy is to invest capital in technologies that allow use of lower priced fuels, such as coal. While considered by several companies in the Houston area, coal conversion has been ruled out for a number of reasons relating to economics, environmental regulations, logistics, and convenience. Underlying these analyses is the perception that gas supplies will be plentiful for several decades and that shifting to coal will not reduce the risk of a shutdown resulting from fuel supply interruptions. Indeed, given uncertainties over transportation, labor, leasing, and strip mining regulations, coal use would increase such risks in the minds of many.

Several factors make coal conversion economically unattractive at the present time. Capital costs are substantial; conversion essentially means building a new boiler and fitting it with the necessary pollution control equipment. This is especially unappealing to companies whose boilers and plants are new or recently renovated and operate at high efficiencies. More telling, however, are operating costs for coal boilers which, in the state of Texas, are too high to allow economic recovery of capital investments. Operating costs are compounded by pollution control requirements. In addition to the labor, maintenance, and energy penalty occasioned by scrubbers, there are significant costs related to solid waste disposal. Houston is located on the 100-year flood plain and scrubber sludge would have to be transported 50 miles to conform with local watershed protection regulations. As discussed below, advanced technologies will not be available for some time in this industry.

Coal use is discouraged by other logistical and convenience factors that have both an economic impact and carry a weight of their own. Space is a problem at many plants, although this could probably be alleviated (at a significant cost) by overhead storage bins and remote stockpiling. Reliability of coal systems is also a major concern. Coal supplies, as mentioned above, are insecure in the minds of some. In addition, coal is a completely new fuel for the industry and there is some concern whether sufficient technical expertise could be generated to keep the system running at levels consistent with required utilization rates and energy needs. A related point is the opportunity cost of shifting personnel from their current positions in the firm to overcome the national lack of trained coal technicians.

Despite these disadvantages, most companies recognize that either the Fuel Use Act or the exigencies of the market may require them to shift to coal at some point. Two types of response were encountered in the interviews. The first was that if coal use became necessary, minemouth gasification would be the appropriate technology. Several advantages would accrue from this strategy. They include compatibility with existing boiler and flame-heat technologies and investments, cheap transportation through existing pipelines, easy disposal of residuals into mines, and avoidance of logistic, space, and expertise problems at the refinery. One proponent of this view is working with the Department of Energy on a gasification demonstration project. Those holding this view, however, see shifting to coal-based gas as a long-term contingency plan, and have no immediate investment plans.

The second response is to consider using solid coal at an existing plant in the near future. One company is currently studying the feasibility of converting its refinery in the Gulf Coast region. Recent and anticipated increases in the price of natural gas warrant consideration not only for replacing existing gas-fired boilers with coal-fired ones, but also of the possibility of extending the use of steam to applications currently served by direct fire processes. Steam processes could increase significantly from their current level of approximately ten percent of total plant energy use. In addition, on-site production of electricity is being considered.

These positive factors and the abundance of nearby coal resources have led companies with plants in other parts of the country to also consider coal. Plans have been developed for new coal-fired refineries and chemical plants to be sited in Illinois and North Carolina. The ultimate level of coal use in the refinery industry, however, may be constrained by the option of siting plants overseas, nearer to sources of raw materials in countries where environmental regulations are not as strict.

While some awareness of new technologies like FBC and gasification was exhibited, these are unlikely to be on-line in this industry until at least the mid-1990s. In addition to the considerable development, which is perceived to be necessary to get these technologies to a stage where they are sufficiently economical and reliable, there is the problem of lead times. The industry is somewhat like the utilities in that lead times are about ten years. This means that no new technologies will be employed until ten years after they are demonstrated to be commercially viable. While scrubbers are perceived as problematic in terms of reliability, energy costs, and solid waste, they are given active consideration for near-term projects. In plants that do use coal, cogeneration will probably increase and, thus, displace some utility-generated electricity.

Food Processing

Food processing, the least energy-intensive of the major energy-consuming industries, is an unlikely candidate for increased coal use. While energy consumption is substantial and boiler steam is a significant use of energy, several factors discourage increasing coal consumption, especially at existing plants. The foremost reason is that boiler sizes and utilization rates are such that the economies of scale for economical coal use are rarely present. A secondary consideration is that since energy costs are only a small fraction of total costs, the capital costs, inconvenience, and risks associated with coal conversion are unwarranted.

The food processing industry consumes 1.0 Q of energy annually, less than ten percent of which is coal. Boilers account for over 80 percent of energy consumption, and almost all steam output is for process uses. Thus, the total amount of fuel burned in boilers in the food industry is equivalent to that burned in the chemical and primary metals industries. Cogeneration is uncommon, and space heat accounts for a small portion of steam output. Boilers range in size from less than 10,000 lb/hr to somewhat over 100,000 lb/hr. No boilers of over 200,000 lb/hr were encountered. Utilization rates, including redundant capacity, are less than 50 percent.

Generalizations about fuel use are difficult because a substantial mix on both regional and boiler size bases was encountered. Some boilers of less than 100,000 lb/hr fire coal while others of over 125,000 lb/hr burn oil or natural gas. There is regional fuel diversity, but coal use is restricted to the Great Lakes and Appalachia regions. There is, however, significant use of oil and natural gas in these regions. The industry, which is very dispersed, burns a variety of fuels for steam raising.

The food processing industry, while accounting for a significant portion of total industry boiler capacity, is only moderately energy intensive. Food processing establishments rarely exhibit the economies of scale necessary to make investment in coal technologies an attractive alternative. In addition, because other costs, notably materials (70 percent) and labor (10 percent), are greater contributors to product costs than energy, companies are reluctant to accept the substantial risks and costs to their entire operation that coal use entails in order to achieve a small reduction in total costs. The cost of coal use most frequently mentioned was capital costs, especially for conversion of existing plants, and perceived risks, including uncertainty of supplies and lack of experience with coal-fired boilers.

Coal conversion in the food industry is unlikely for a variety of reasons. Capital costs for boilers, coal handling equipment, and pollution control devices, are the main disincentives to conversion. Profit margins are often quite small in the food industries and the availability of capital may be a restricting factor. Most of the capital that is available will be invested in production equipment. High capital cost energy projects will generally be given low priority status.

Steam-use profiles further mitigate against conversion to coal in most food processing plants. Many individual food industries--canned fruits and vegetables, beet sugar, wet corn milling, etc.--are predominantly seasonal activities. Others, although less influenced by seasonal variation, are characterized by single shift operations. Finally, batch processing techniques are still common in the food industries. Each of these three factors has the effect of lowering overall boiler utilization rates. Similarly, most processes are carried out at low temperature, which discourages the feasibility of cogenerating electricity.

Space availability is a constraint at some plants, and labor costs are proportionately higher for coal and, as such, discourage investment. Government and industry food quality standards also tend to prevent conversion to coal-fired steam facilities. In existing coal-fired plants, air quality regulations may be problematic. Scrubbers will not be installed because of space, cost, and solid waste disposal factors, and low sulfur coal will be used where possible. In cases where it is legally permissible, some plants currently using coal may switch to oil or gas.

Fabrication and Assembly--The Case of the Automotive Industry

Metal fabrication and assembly establishments are not major consumers of energy, but a discussion of the perceptions of one group of companies is included in order to illustrate the problems of coal use for firms whose scale and intensity of energy use is low. While some companies are now burning coal under boilers and others will do so in the future, there are several reasons why these firms are hesitant to consider using coal. Energy use levels are low and the economies of scale required to make investments in coal technologies are not present. In addition, energy costs are only a small portion (<3 percent) of total product costs, and companies are loath to accept the perceived inconvenience, unreliability, and costs of a coal system, to achieve minimal reductions in total costs. Along the same lines, since capital is scarce, manufacturers seek investments that will offer the greatest return to their entire operation, such as those in product development and marketing endeavors. Finally, many small manufacturers think that enough natural gas is available to serve their energy needs economically. It appears, then, that prospects for coal conversion in the fabrication and assembly establishments are dimmer than in other more energy-intensive industries.

The interviews discussed below focused on the automotive industry and its suppliers. These firms have facilities throughout the Great Lakes and Appalachia regions, as well as a fair number of facilities along the Gulf Coast. The interviews focused on the Great Lakes states and it is assumed that the negative conclusions regarding coal use would be even more pronounced in the Gulf Coast region, where transportation costs, plentiful supplies of natural gas, and a lack of experience all detract from the desirability of using coal.

Steam boilers range in size from a few horsepower to over 200,000 lb/hr. The age of boilers is apparently fairly evenly distributed, including some boilers more than 40 years old as well as many of more recent construction. Automobile production has been a growth sector in the economy, and it is anticipated that new boilers will be built in the future. Boilers are used mainly for space heat and utilization rates tend to be very low, as few plants operate continuously. Boiler heat is cut back significantly at night and on weekends, and there are severe seasonal variations in plant temperature requirements. Similarly, electricity consumption, which in some cases occurs at very high levels, is also irregular as machines and lighting are typically used only for two shifts on weekdays. Space heat requires steam of less than 150 psi, an amount well below that required for electricity generation and, therefore, a technical impediment to effective cogeneration.

Coal accounts for perhaps one-third of total fuel for these boilers. While it is undoubtedly more common for large boilers to burn coal, no approximate breakeven capacity between oil or natural gas and coal is ventured because of the diversity stemming from company policy and regional influences. As in other industries, coal use is most common in the Great Lakes and Appalachia regions and exceptional in the Gulf Coast states, where natural gas predominates. Tradition, supply, and transportation, as well as economics, account for these concentrations.

Coal can be an uneconomical boiler fuel in automobile manufacturing applications for a variety of reasons. Capital costs for coal boilers are much higher than for alternatives. In addition to a larger firebox, coal boilers require special fuel and ash handling equipment, and pollution control devices. For new boilers, capital costs are estimated at two to four times those of oil or gas boilers, and for retrofit installations, they may run even higher. These costs are especially critical in the context of the typical automobile manufacturing firm where energy costs are one to five percent of total product costs. Energy investments are, thus, likely to result in less reduction in overall costs than similar investments related to materials and labor. In a capital-constrained situation, then, energy investments will receive a lower investment priority.

In an unconstrained situation, the rationale for investment in a coal boiler is to achieve savings by reducing fuel costs by an amount greater than the capital cost differential over oil and gas boilers. In the automotive sector, however, utilization rates and levels of fuel use are so low that the desired savings are rarely attained over the life of the boiler. A similar logic applies to on-site electricity generation. While it is the case that automobile manufacturers are among their local utility's largest customers, electricity is but a tiny fraction of total manufacturing costs and, thus, is a poor target for scarce capital. In addition, since load curves fluctuate severely, utilization rates are low and the desired savings are rarely achieved. Finally, coal use is uneconomical because the overall level of steam use is below the threshold required in order to achieve the steep economies of scale associated with coal-based energy technologies.

In addition to direct capital costs, coal use entails other costs to the firm. Labor, operation, and maintenance costs are relatively higher than for other fuels. Much higher are the opportunity costs and risks associated with coal use. As mentioned above, investing in expensive coal boilers and auxiliary equipment diverts funds from more lucrative labor- and materials-saving processes and from research and development and marketing ventures. As detailed below, the space, inconvenience, community relations, and uncertainty factors associated with coal use also expose the company to unwarranted risks and costs.

Space is a major consideration in fuel choice decisions. Existing plants are often in urban areas where space for larger powerhouses, stockpiles, and pollution control equipment is not readily available. These constraints can be remedied at a cost with options such as overhead storage bins, remote site coal depots, and rearrangement of the existing plant configuration. For newer plants, built in surburban or rural sites, and planned with fuel uncertainties in mind, space is not as critical a constraint. One company that currently uses natural gas reported dedicating space at all new plants for a coal powerhouse complex should conversion become necessary for economic or public policy reasons.

Automobile manufacturers also reported concern over the inconvenience entailed by coal use. As with capital, they felt any activity, such as coal handling, which diverted attention from their primary purpose, producing automobiles was not in the company's best interests.

Reliability of coal systems is another reason for the skepticism of many in the automobile manufacturing sector. Some supply problems were reported, and there was concern that they will become exaggerated in the future as mines become more oriented towards the large utility market. While deliveries were usually assured, coal quality control was reported as a major vulnerability because auto producers buy coal in small quantities and lack blending equipment. There was also concern over technologies. Conventional boilers were seen as adequately reliable, but, should these require modification or replacement for environmental reasons, there is much hesitation to commit to "unproven" technologies such as scrubbers, FBC, and gasification. Here the logic is that energy costs are such a small portion of total costs that companies are willing to pay for non-coal alternatives in order to protect their entire operation from the possibility of a shutdown resulting from an energy system failure.

In addition to plant operations, automobile manufacturers must, as producers of consumer goods, be concerned with their image in the community. The interviews revealed that the companies were very conscious of how the public interpreted their energy choices. The companies who favored natural gas do so in part because it is a cleaner fuel with fewer environmental impacts. Those that have built coal plants in recent years explain that those decisions reflect, to some degree, their corporate responsibility to help the country through its energy problems by burning more abundant fuels. These companies expressed some concern that using coal might tarnish their image because of its environmental effects.

Against these costs and uncertainties, there are some advantages of coal use in the automobile manufacturing sector that have been recognized by firms now on coal, and whose imperative may grow in the future. Two arguments generally offered in support of coal utilization are lower costs (owing to future expected rises in oil and natural gas prices) and the security of domestic availability. While, as argued above, the net costs of coal are at present higher than those of other systems, companies betting on coal anticipate that sharp increases in oil and natural gas prices will soon reverse this situation. The second issue, availability, must be discussed in the context of perceived supplies of alternative fuels.

While there was substantial agreement that future oil supplies are limited, and automobile manufacturers should shift to alternative fuels, there was a polarity of views regarding natural gas that led to two perceptions about coal. On one side were those who foresaw future shortages of gas and the distinct possibility of supply interruptions; this led them to consider coal, with all its disadvantages, as a viable and often preferable alternative. On the other side were those who expected a "forty year gas supply"--a number quoted with remarkable frequency--and adequate early warning by the market should supplies be interrupted. These companies felt that the 1976 to 1977 gas curtailments in many parts of the country were the result of inventory mismanagement and not the precursor of impending shortages. They also perceive themselves as being in an enviable position in contrast to that of higher energy users in other sectors. Being small consumers of gas, they can afford to stay in the market much longer than other sectors, should prices rise and supplies decline, and thus, have more time for adjustment. One strategy proposed by many of the natural gas optimists was to develop a gas/oil capability at all plants to minimize risks of shutdown as a result of shortages of one fuel or another. One company was reportedly so certain of future gas supplies that new plants do not even have boilers; space and process heat is supplied by furnaces and unit heaters. Even these optimists, however, are designing new plants that could easily be converted to coal should their view of the future prove to be erroneous.

Small Producers

Findings for small producers in a variety of industries are presented together here because it is clear that the small producers have much more in common with each other than they do with large firms in their particular industries. Small producers are defined as firms whose steam requirements are less than 50,000 lb/hr. Small producers from chemicals, metals, and petroleum refining stated categorically that direct use of coal was inappropriate to their operations for a variety of reasons, and that coal use could be increased only with the implementation of a gasification technology. The major reasons for their reluctance to accept coal relate to economies of scale and the resources available to these firms.

There are several ways in which the operational and organizational structures of the small producers fail to achieve the economies of scale necessary for economical use of coal as a boiler fuel. In order to justify their high capital costs, coal systems must displace considerable amounts of oil and natural gas. While this is often possible in large firms, small producers rarely have the energy expenditures required to make investments in coal systems economical, as boilers are generally small (less than 100,000 lb/hr) and utilization rates low (less than 50 percent). In addition, energy costs are a smaller fraction of total costs than in the large firms because of the substantial portion of costs allocated to activities like plant management and maintenance, which are significant fractions at low levels of scale.

The small producers also indicated a number of operational impediments to coal use. Space is a very important factor. In contrast to large plants where there is always some slack space to "play with," small facilities simply do not have the room for the storage and operational components of a coal-based system. Equipment can also be a problem. Whereas a large plant might very well have machinery that could serve as coal moving devices, small plants are less likely to have such equipment in their stock. Product purity can also present difficulties. At large plants it is possible to segregate coal piles, combustion facilities, and waste products from production areas, so that contamination is not a danger. At small plants, heat sources and work areas are often so close together that products may become tainted with coal residuals. This problem is particularly important for the small firms in the steel and chemical industries, which make specialty products for which quality control standards are very high.

One solution posed by many small firms to these economic and operating costs is to use gasified coal. Buying coal, gasified at a centralized plant, would perhaps be more costly than natural gas at current prices, they say, but it would alleviate many of these issues. Existing boilers could be used and the space, equipment, and product purity problems cited above would be eliminated. It is very clear from the interviews that gasified coal is perceived as the only feasible alternative to natural gas and oil for small producers.

SAMPLING INTERVIEW METHODOLOGY

The interview results presented above were the outcome of an extensive survey of plant and corporate level personnel in the five industrial sectors. Plant managers and powerhouse engineers were queried in order to determine day-to-day operating problems and advantages of a coal-based system at their particular facilities. These interviews produced many insights into problems regarding coal deliveries, space, labor force experience, and boiler system operation and reliability. In order to complement these data with a wider perspective, interviews were subsequently conducted with corporate-level personnel in the same companies; these respondents ranged from members of the energy planning staff to vice-presidents. Hence the focus was the economics of fuel and technology choices, the compatibility of coal-based systems with short- and long-term corporate objectives, the range of options available for meeting energy needs, and the logistics of procuring technologies and fuels. Together, these two sets of interviews present a complete picture of the perceptions that influence a firm's decision to opt for coal or some other energy resource.

Sampling was conducted as follows. National Environmental Data System (NEDS) Point Source Air Emissions Data were obtained for Pittsburgh and Houston and divided into five industrial sectors: Chemicals, Primary Metals, Petroleum Refining, General Manufacturing, and Food Processing. Plant-level interviews were then conducted with a representative group of large and small firms from each of the five sectors in the two regions. These respondents were also asked to suggest the names of corporate-level personnel who could provide information about the wider questions regarding coal use, and these persons were contacted. In addition, in order to separate industry-specific from regional influences, regarding the desirability of coal use, a third set of interviews was conducted. These were of corporate-level personnel from other large companies in the five sectors that did not have operations in either Pittsburgh or Houston.

In total, forty-three respondents from thirty firms were interviewed. The cases where only one interview was obtained from a company were those where the operation was so small that no further information could be gained from a corporate-level interview and those supplemental interviews of non-Houston or Pittsburgh companies where only corporate level personnel were queried. The interviews were distributed as follows:

	Plant	Corporate	Total
Chemicals	6	6	12
Primary Metals	5	6	11
(Ferrous)	(4)	(2)	(6)
(Non-Ferrous)	(1)	(4)	(5)
Petroleum Refining	3	8	11
Manufacturing	0	4	4
Food Processing	2	3	5
Total	16	27	43

These interviews were regionally distributed as follows:

Houston	11
Pittsburgh	18
National corporations with no operations in Houston/or Pittsburgh	14
Total	43

The distribution emphasized, roughly, primary metals and specialty chemicals in Pittsburgh and petroleum refining and petrochemicals in Houston.

The sample, while not scientific, is defensible on several grounds. In the first place, a rule of thumb was to continue interviewing until no new information was obtained from the respondents. In most cases one, two, or three basic positions were discerned for each industry. In addition to its internal consistency, the sample is felt to be representative of the industry because it is in accord with existing published materials on industry-specific preferences over coal use.

Two possible weaknesses in the sampling process are acknowledged. The first is the bias that might have been introduced by those who responded to our plea for cooperation. There were, inevitably and unfortunately, some in the sample population who were "too busy," or "not at liberty to discuss corporate policy," and would not participate in the interviews; this was the case for approximately 15 percent of the inquiries. It is possible that these people shared a consistent view about coal use that is not represented in the study. The second potential weakness is that the research team had no basis for validating the information given. That is, it is possible the respondents presented the information they wanted EPA to hear, which might be at variance with the truth. This problem, however, was minimized by the interview format. The one-half to two-hour in-person and telephone interview allowed the enumerators ample opportunity to probe for internal inconsistencies and to question responses that contradicted other sources of information. For these reasons, it is felt, for the most part, that the survey results accurately portray the energy situation in the various industrial sectors.

APPENDIX B

TECHNOLOGIES: METHODS OF COMPARISONS, DATA SOURCES, AND DETAILED RESULTS

METHODS OF COMPARISONS

Discharges to the environment and resource requirements are determined for all individual operations from mining through steam production. In order to compare technologies, a trajectory, or sequence of operations from mining through steam production, was defined for each technology. These are listed in the tabulation displayed below.

	Extraction	Processing	Transportation	Steam Production
1.	Eastern underground mine	--	Rail	Conventional combustion (CC)
2.	Eastern underground mine	Physical coal cleaning	Rail	CC
3.	Eastern underground mine	--	Rail	CC with flue gas desulfurization (FGD)
4.	Eastern underground mine	Physical coal cleaning	Rail	CC with FGD
5.	Eastern underground mine	--	Rail	Fluidized-bed combustion (FBC)
6.	Eastern underground mine	Physical coal cleaning	Rail	FBC
7.	Eastern underground mine	--	Rail	Low-Btu gasification - gas burned in the boiler
8.	Western strip mine	--	Rail	CC
9.	Western strip mine	--	Rail	CC with FGD

10. Western strip mine	--	Rail	FBC
11. Western strip mine	--	Rail	Low-Btu gasification - gas burned in the boiler

For each operation (also referred to as a "module"), data for discharges and resource requirements are reduced to quantities per million Btu of output from the module. For a given level of steam production and a given trajectory, the associated quantities of discharges and resource requirements are obtained by multiplying the total Btu output by the appropriate unit factors for each module, and summing over all modules in the trajectory. Proper account is taken of the fact that the early modules in a trajectory each must produce more energy than subsequent modules because of efficiency losses.

As can be seen in the previous tabulation, eleven separate trajectories have been established utilizing the different mining, processing, and steam production modules. These eleven trajectories constitute the complete list for making direct comparisons of the coal technologies. Combinations of these trajectories, with various levels of delivered energy (in this case, process steam), constitute a "technology mix." A graphical display can help explain this methodology.

In Figure B-1 all of the elements in the methodology are shown: modules, trajectories, and mixes of technologies (or more precisely, mixes of trajectories). The methodology allows three types of comparisons. First, individual modules, such as the coal conversion technologies, may be assigned an equal amount of energy delivered and then compared. This type of comparison is employed (as well as the other two types of comparisons) in Chapter 7 on air quality, and is the least frequently used mode of comparison in the report. The comparison of modules alone is most useful when the differences in single technologies are emphasized, and when comparisons are being made to other sources of information that do not account for the entire mining-to-end-use trajectory. Second, as noted above, the trajectories themselves may be compared. In this mode, each trajectory is assigned an equal amount of energy delivered. Note that in such a comparison, the amount of mined coal required for different trajectories may vary, since some trajectories are overall more or less efficient than others. The mined coal requirements, of course, may also differ because of differences in the Btu content of the coal originally assigned to the trajectory. And third, combinations of trajectories may be compared as "technology mixes," where each mix is assigned an equal amount of energy delivered. Technology mixes are aggregations of selected trajectories in varying proportions. In all three types of comparisons, a computer program provides a system for accounting for the flows of coal and computing the resource requirements and discharges at each stage of coal production and use. Description of the actual technology mixes employed is provided in Chapter 6.

DATA SOURCES

The primary sources of data and information used in this study were Environmental Assessment contractors and other EPA contractors. The primary

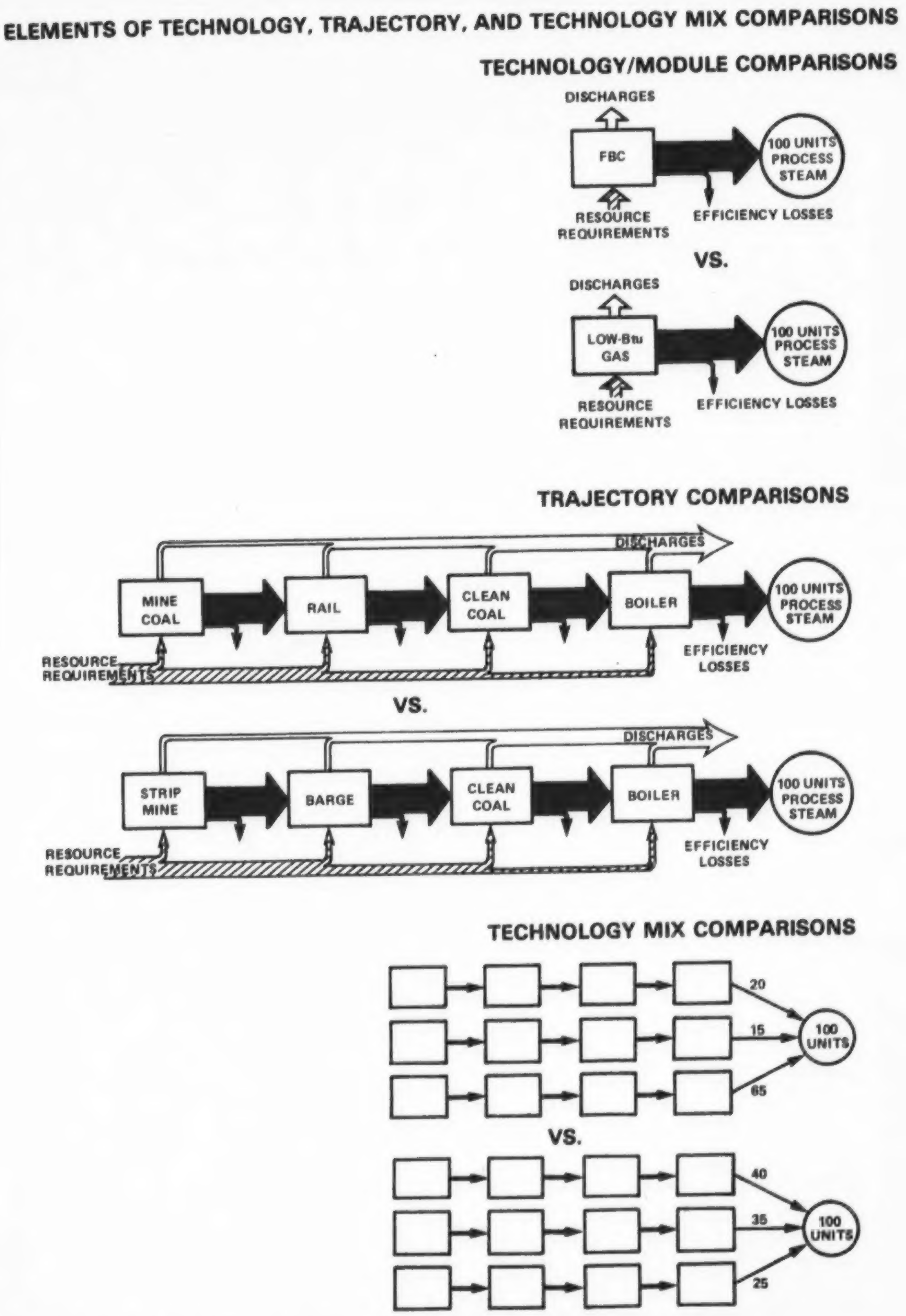
ELEMENTS OF TECHNOLOGY, TRAJECTORY, AND TECHNOLOGY MIX COMPARISONS
TECHNOLOGY/MODULE COMPARISONS
DISCHARGES
FBC
100 UNITS PROCESS STEAM
RESOURCE REQUIREMENTS
EFFICIENCY LOSSES
VS.
DISCHARGES
LOW-Btu GAS
100 UNITS PROCESS STEAM
RESOURCE REQUIREMENTS
EFFICIENCY LOSSES
TRAJECTORY COMPARISONS
DISCHARGES
MINE COAL
RAIL
CLEAN COAL
BOILER
100 UNITS PROCESS STEAM
RESOURCE REQUIREMENTS
EFFICIENCY LOSSES
VS.
DISCHARGES
STRIP MINE
BARGE
CLEAN COAL
BOILER
100 UNITS PROCESS STEAM
RESOURCE REQUIREMENTS
EFFICIENCY LOSSES
TECHNOLOGY MIX COMPARISONS
20
15
65
100 UNITS
VS.
40
35
25
100 UNITS

Figure B-1. Technology mix methodology.

contact, reports by the primary contractor, and secondary sources are given in the following paragraphs for each of the technologies.

Conventional Combustion

The primary contact was John P. Abraham of PEDCo Environmental, Chester Towers, Cincinnati, Ohio. Abraham completed a portion of the module characterization data sheet. The remainder of the data and information used was obtained through an interview with Abraham and from the following reports:

1. "Task 3 Summary Report, Uncontrolled Emissions from Industrial Boilers," PEDCo report to EPA, IERL, RTP, August 29, 1978 (EPA Contract No. 68-02-2603/3).

2. "Capital and Operating Costs for Industrial Boilers," PEDCo report to EPA, OAQPS, RTP, June 1979 (EPA Contract No. 68-02-2603/49).

Flue Gas Desulfurization

The primary contact was James C. Dickerman of Radian Corporation, 8500 Shoal Creek Boulevard, Austin, Texas. Information was obtained through two telephone conversations with Dickerman and from a draft document prepared by Radian Corporation for EPA (now published as, J. C. Dickerman and K. I. Johnson, Technology Assessment Report for Industrial Boiler Applications: Flue-Gas Desulfurization. EPA, IERL, RTP, EPA-600/7-79-178i, November 1979 [NTIS No. PB 80-150873]).

Physical Coal Cleaning

The primary contact was Alexis W. Lemmon, Jr., of Battelle Columbus Laboratories, the original Environmental Assessment (EA) contractor for this technology. The module characterization data sheet was completed from information developed during the course of the EA program. Reports used include the following:

1. "The Use of Coal Cleaning for Compliance with SO_2 Emission Regulation," Draft Battelle report to EPA, IERL, RTP, July 1979 (EPA Contract No. 68-02-2163).

2. "Environmental Assessment of Coal Cleaning Processes: Technology Overview," Draft Battelle report to EPA, IERL, RTP, June 1979 (EPA Contract No. 68-02-2163).

Fluidized-Bed Combustion

The EA contractor for this technology currently is GCA Corporation, Technology Division, Burlington Road, Bedford, Massachusetts. The primary contact was Paul F. Fennelly. GCA prepared a completed module characterization data sheet, and the remaining information was obtained through an interview with three GCA staff members. Market projections for fluidized-bed combustion in the industrial sector are documented in, "Environmental Research

Needs for Fluidized-bed Combustion Residues," a paper presented by Fennelly at the Workshop on Solid Waste Research and Development Needs for Emerging Coal Technologies, sponsored by the American Society of Civil Engineers (Power Research Council) and the Electric Power Research Institute, held at San Diego, California, April 23-25, 1979.

Low-Btu Gasification

The EA contractor for this technology is Radian Corporation, Austin, Texas. The primary contact was Gordon C. Page. The following reports were used as secondary sources of information:

1. **"Environmental Aspects of Retrofitting Two Industries to Low- and Intermediate-Energy Gas from Coal," EPA-600/2-76-102 (NTIS No. PB 253946), Battelle report to EPA, April 1965.**

2. **"Market Opportunities for Low- and Intermediate-Btu Gas from Coal in Selected Areas of Industrial Concentration," HCP/T 2441-02, UC-90C, Report prepared by SRI International for the U.S. Department of Energy, June 1978.**

DETAILED RESULTS

The detailed data that are summarized in the main body of this report are presented in this section for further study.

The modules employed in the comparison of selected technologies for the use of coal in industrial boilers are listed in Table B-1. The module characterization factors for 14 parameters also are given in Table B-1. The efficiency is defined as the Btu output of the module divided by the Btu input to the module. All other factors state the number of units noted in each column heading per million Btu output of the module. For most modules the units of the factor are lb/10^6 Btu. When these factors are multiplied by the number of Btu per year produced by a module, the result is lb/yr. The unit for water consumption is gallons per million Btu and the result of multiplying this factor by Btu/yr is gal/yr.

A somewhat different unit is required for land use and for labor. The labor factor is expressed as man-yr/10^6 Btu. Multiplication by Btu/yr gives the number of persons required by all of the plants producing the stated energy output in a year. The factor is derived from the labor required by a plant of a given size. The model plant size used in this study is 100,000 pounds of steam per hour. If the heat content of the steam is taken to be 1,000 Btu/lb and if the load factor is 0.45, the annual output is 3.94×10^{11} Btu/yr. The assumed labor required for a boiler burning coal A (Eastern coal) by conventional combustion is six persons. The labor factor is then 6 divided by 3.94×10^{11} Btu/yr or 15×10^{-6} man-year per million Btu, as shown in Table B-1 for conventional combustion, coal A, under labor. The land-use

TABLE B-1. LIST OF MODULES WITH MODULE CHARACTERIZATION FACTORS (UNIT PER 10^6 BTU OUTPUT FROM THE MODULE)

		Discharges to Air					Solid Wastes					Resource Requirements			
Module	Efficiency[(a)]	NO_x, lb	SO_2, lb	CO_2, lb	Particles lb	Total Organic, lb	Tar, lb	Ash, lb	Sludge, lb	Tailings, lb	Spent Bed, lb	Water, Gal	Land 10^{-6}Acre-yr	Labor, 10^{-6}Man-yr	Raw Materials, lb
Eastern underground mine	0.99	-	-	-	-	-	-	-	0.016	2.28	-	1.4	48	8.6	-
Western strip mine	0.998	-	-	-	0.07	-	-	-	-	-	-	1.1	18	1.2	-
Rail transportation	1.0	0.02	0.0014	19.	0.0015	-	-	-	-	0.083	-	-	33	2.7	-
Physical coal cleaning, Coal A	0.91	0.0078	0.06	1.9	0.0007	0.0013	-	-	-	18.5	-	6.5	5	1.0	-
Physical coal cleaning, Coal B	0.91	0.011	0.014	2.6	0.005	0.0018	-	-	-	11.5	-	9.0	5	1.0	-
Fluidized-bed combustion, Coal A	0.823	0.6	0.5	247.	0.038	0.004	-	14.2	-	-	32.3	14.5	16	17.5	41.3
Fluidized-bed combustion, Coal B	0.813	0.6	0.5	256.	0.038	0.004	-	10.6	-	-	5.0	14.5	5.3	17.5	5.9
FBC, cleaned Coal A	0.83	0.6	0.5	240.	0.038	0.004	-	6.8	-	-	22.0	14.5	10.6	17.5	27.0
Conventional combustion, Coal A	0.82	0.8	7.0	250.	0.037	0.052	-	11.2	-	-	-	24.0	7.1	15.0	-
Conventional combustion, Coal B	0.82	1.0	1.5	270.	0.023	0.065	-	7.0	-	-	-	24.0	5.9	15.0	-
Conv. comb., cleaned Coal A	0.83	0.69	4.3	250.	0.017	0.046	-	5.2	-	-	-	24.0	5.4	15.0	-
Conv. comb., FGD, Coal A	0.80	0.8	0.7	250.	0.036	0.052	-	11.2	13.0	-	-	37.2	11.	27.5	6.0
Conv. comb., FGD, Coal B	0.80	1.0	0.15	270.	0.023	0.065	-	7.0	2.5	-	-	34.9	6.7	27.5	1.3
Conv. comb., FGD, Cleaned Coal A	0.81	0.69	0.7	250.	0.017	0.046	-	5.2	6.9	-	-	36.0	7.4	27.5	3.1
Low-Btu gasification, Coal A[(b)]	0.542	0.23	0.43	370.	0.013	0.001	6.6	16.6	-	-	-	52.0	9.7	32.	-
Low-Btu gasification, Coal B[(b)]	0.574	0.23	0.088	375.	0.013	0.001	6.6	9.8	-	-	-	52.0	7.7	32.	-

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(a) Btu output from the module divided by Btu input to the module

(b) Includes gasification of coal and combustion of low-Btu gas produced in a boiler factor is derived similarly, with the land required by ash or other solid waste disposal included in the factor. Coal B in the tables refers to Western coal (see Chapter 6).

The factors listed in Table B-1 pertain to normal operation of each module. Variations that result from startup and shutdown, wide load swings, coal feed variations, and other abnormal operations have not been considered in determining the factors. The factors should be constant for different facility sizes, that is, each discharge or resource is proportional to the total output, irrespective of size. This is not strictly true for the land-use and labor factors, which would decrease somewhat as the facility size increases. A much greater change, in these two factors only, would occur for different load factors. However, since the land-use and labor factors listed were developed for the boiler size and load factor that are near the average for coal-fired boilers, the totals calculated from different factors for different facility sizes are used in conjunction with detailed size-distribution assumptions.

There is potential for error in some of the NO_x emission factors. For conventional combustion of Eastern and Western coal, and for combustion of physically cleaned Eastern coal, emission factors from Compilation of Air Pollution Emission Factors (3d edition, through Supplement 10, 1980, EPA report AP-42, NTIS No. PB 275525) were used. This document relates NO_x emission to the weight of coal burned. Since Western coal has a lower Btu content per pound than Eastern coal, the resulting NO_x factor for Western coal on a Btu basis is higher than for Eastern coal. Similarly, cleaned coal has a higher Btu content than uncleaned coal and, therefore, a lower NO_x emission factor when the approach employed in AP-42 is used.

The factor for the water requirement for fluidized-bed combustion is lower than that for conventional combustion. When we asked GCA staff members about this difference, they reported that the FBC factor was as good as they could derive given the current status of the technology. The factor for ash from FBC includes a small amount of char, which would be disposed of with the ash.

The detailed results of the calculation of total discharges and resources requirements for the direct comparison of the selected technologies are given in Tables B-2 and B-3. The trajectories assumed for each technology are defined in significance. These totals for each discharge and resource also were shown graphically and in tabular form in the main body of the report. The tables presented here show the contribution of each trajectory to the totals. The designation of each technology mix studied, and the tables that report the results of each are given in the following tabulation.

Technology Mix	Table Numbers
Industrial boilers in 1980	B-4 and B-5
Industrial boilers in 2000	B-6 and B-7
Clean, all Eastern coal in 2000	B-8 and B-9
High level of scrubbing in 2000	B-10 and B-11

High level of low-Btu gasification in 2000	B-12 and B-13
High level of fluidized-bed combustion in 2000	B-14 and B-15

The assumptions contained in each of these technology mixes are summarized in Chapter 6.

TABLE B-2. TRAJECTORIES USED FOR DIRECT COMPARISON OF TECHNOLOGIES AND MINED-COAL REQUIREMENTS OF EACH TRAJECTORY

	EXTRACTION	PROCESSING	TRANS.	END USE	STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	100	122
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	100	132
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	100	125
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	100	136
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	100	122
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	100	132
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	100	185
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	100	122
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	100	125
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	100	123
11	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	100	174

TABLE B-3. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: DIRECT COMPARISON OF TECHNOLOGIES [Each trajectory produces 100 × 10^{12} Btu of steam per year (equivalent to 250 steam plants]

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	82	700	27,317	5.20	4	100
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	72	437	27,518	4.76	2	100
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	82	70	27,375	5.20	4	100
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	72	78	27,580	4.76	2	100
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	62	50	27,009	0.40	4	100
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	63	57	26,518	0.56	4	100
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	27	43	40,506	0.10	2	100
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	102	150	29,317	6.50	11	100
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	103	15	29,375	6.50	11	100
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	62	50	27,937	0.40	13	100
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	26	9	40,810	0.10	14	100

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	1,120	2	288	--	100
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	520	2	2,541	--	100
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	1,120	1,302	295	--	100
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	520	692	2,604	--	100
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	1,420	2	287	3,230	100
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	680	2	2,541	2,200	100
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	660	1,660	3	436	--	100
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	700	--	10	--	100
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	700	250	10	--	100
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	1,060	--	10	500	100
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	660	980	--	14	--	100

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	2,571	10,588	2,878	--	100
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	3,368	11,473	3,084	--	100
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	3,895	11,225	4,162	600	100
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	4,592	11,943	4,374	310	100
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	1,620	11,442	3,123	4,130	100
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	2,418	11,993	3,334	2,700	100
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	5,458	15,915	5,285	--	100
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	2,534	6,810	1,976	--	100
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	3,627	7,045	3,237	130	100
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	1,585	6,803	2,230	590	100
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	5,392	9,655	3,879	--	100

TABLE B-4. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: INDUSTRIAL BOILERS IN 1980

	EXTRACTION	PROCESSING	TRANS.	END USE	STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	480	585
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	350	463
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	70	88
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	0	0
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	0	0
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	0	0
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	0	0
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	300	366
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	0	0
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	0	0
11	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	0	0
				TOTAL	1,200	1,494

TABLE B-5. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: INDUSTRIAL BOILERS IN 1980

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO$_x$ (MILL LB)	SO$_2$ (MILL LB)	CO$_2$ (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	396	3,361	131,122	24.96	19	480
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	253	1,531	96,313	16.65	7	350
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	58	49	19,163	3.64	3	70
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	--	--	--	--	--	--
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	307	451	87,951	19.50	33	300
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	--	--	--	--	--
10.	WEST. STRIF MINE , -		RAIL ,	-FBC B ,	--	--	--	--	--	--
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	--	--	--	--	--	--
		TOTAL			1,014	5,391	334,549	64.75	61	1,200

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	5,376	9	1,383	--	480
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	1,820	7	8,893	--	350
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	784	911	207	--	70
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	--	--	--	--	--	--
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	2,100	--	30	--	300
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	--	--	--	--	--
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	--	--	--	--	--
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	--	--	--	--	--	--
		TOTAL			--	10,080	928	10,513	--	1,200

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	12,340	50,823	13,815	--	480
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	11,790	40,157	10,795	--	350
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	2,726	7,857	2,914	420	70
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	--	--	--	--	--
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	7,602	20,429	5,927	--	300
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	--	--	--	--
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	--	--	--	--
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	--	--	--	--	--
		TOTAL			34,458	119,266	33,451	420	1,200

TABLE B-6. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: INDUSTRIAL BOILERS IN 2000

	EXTRACTION	PROCESSING	TRANS.		END USE		STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL	,	-CONV COMB A	,	1,120	1,366
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-CONV COMB PCCA	,	1,120	1,483
3.	EAST. UNDERGROUND, -		RAIL	,	-FGD A	,	640	800
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-FGD PCCA	,	0	0
5.	EAST. UNDERGROUND, -		RAIL	,	-FBC A	,	320	389
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-FBC PCCA	,	0	0
7.	EAST. UNDERGROUND, -		RAIL	,	-LOW BTU GASIF A	,	160	295
8.	WEST. STRIP MINE , -		RAIL	,	-CONV COMB B	,	960	1,171
9.	WEST. STRIP MINE , -		RAIL	,	-FGD B	,	160	200
10.	WEST. STRIP MINE , -		RAIL	,	-FBC B	,	160	197
11	WEST. STRIP MINE , -		RAIL	,	-LOW BTU GASIF B	,	160	279
					TOTAL		4,800	6,180

TABLE B-7. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: INDUSTRIAL BOILERS IN 2000

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	923	7,842	305,951	58.24	43	1,120
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	810	4,899	308,202	53.27	22	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	528	449	175,200	33.28	24	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	200	161	86,428	1.28	13	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	43	69	64,809	0.16	3	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	984	1,442	281,444	62.40	106	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	164	24	47,000	10.40	18	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	100	80	44,699	0.64	20	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	42	14	65,296	0.16	22	160
		TOTAL			3,794	14,980	1,379,029	219.83	271	4,800

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	12,544	22	3,228	--	1,120
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	5,824	24	28,457	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	7,168	8,333	1,890	--	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	4,544	6	919	10,336	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	1,056	2,656	5	698	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	-	6,720	-	97	--	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	1,120	400	17	--	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	1,696	--	16	800	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	1,056	1,568	--	23	--	160
		TOTAL			2,112	43,840	8,789	35,344	11,136	4,800

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	28,792	118,586	32,234	--	1,120
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	37,727	128,502	34,545	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	24,928	71,840	26,640	3,840	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	5,184	36,615	9,994	13,216	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	8,733	25,463	8,456	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	24,328	65,371	18,966	--	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	5,804	11,272	5,180	208	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	2,536	10,885	3,568	944	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	8,627	15,448	6,207	--	160
		TOTAL			146,660	483,982	145,789	18,208	4,800

TABLE B-8. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: CLEAN ALL EASTERN COAL IN 2000

	EXTRACTION	PROCESSING	TRANS.	END USE	STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	0	0
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	2,240	2,966
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	0	0
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	640	868
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	0	0
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	320	424
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	160	295
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	960	1,171
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	160	200
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	160	197
11	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	160	279
				TOTAL	4,800	6,400

TABLE B-9. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: CLEAN ALL EASTERN COAL IN 2000

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	1,621	9,798	616,405	106.55	44	2,240
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	--	--	--	--	--
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	464	497	176,514	30.47	13	640
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	203	184	84,858	1.78	13	320
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	43	69	64,809	0.16	3	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	984	1,442	281,444	62.40	106	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	164	24	47,000	10.40	18	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	100	80	44,699	0.64	20	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	42	14	65,296	0.16	22	160
		TOTAL			3,619	12,108	1,381,024	212.56	238	4,800

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	11,648	47	56,914	--	2,240
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	--	--	--	--	--
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	3,328	4,430	16,663	--	640
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	2,176	7	8,131	7,040	320
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	1,056	2,656	5	698	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	6,720	--	97	--	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	1,120	400	17	--	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	1,696	--	16	800	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	1,056	1,568	--	23	--	160
		TOTAL			2,112	30,912	4,889	82,557	7,840	4,800

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	75,454	257,004	69,091	--	2,240
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	--	--	--	--
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	29,391	76,438	27,991	1,984	640
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	--	--	--	--
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	7,739	38,379	10,670	8,640	320
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	8,733	25,463	8,456	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	24,328	65,371	18,966	--	960
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	5,804	11,272	5,180	208	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	2,536	10,885	3,568	944	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	8,627	15,448	6,207	--	160
		TOTAL			162,613	500,260	150,128	11,776	4,800

TABLE B-10. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: HIGH LEVEL OF SCRUBBING IN 2000

	EXTRACTION	PROCESSING	TRANS.		END USE		STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL	,	-CONV COMB A	,	0	0
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-CONV COMB PCCA	,	1,120	1,483
3.	EAST. UNDERGROUND, -		RAIL	,	-FGD A	,	1,760	2,200
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-FGD PCCA	,	0	0
5.	EAST. UNDERGROUND, -		RAIL	,	-FBC A	,	320	389
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL	,	-FBC PCCA	,	0	0
7.	EAST. UNDERGROUND, -		RAIL	,	-LOW BTU GASIF A	,	160	295
8.	WEST. STRIP MINE , -		RAIL	,	-CONV COMB B	,	0	0
9.	WEST. STRIP MINE , -		RAIL	,	-FGD B	,	1,120	1,400
10.	WEST. STRIP MINE , -		RAIL	,	-FBC B	,	160	197
11	WEST. STRIP MINE , -		RAIL	,	-LOW BTU GASIF B	,	160	279
					TOTAL		4,800	6,243

TABLE B-11. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: HIGH LEVEL OF SCRUBBING IN 2000

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	810	4,898	308,202	53.27	22	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	1,452	1,253	481,800	91.52	67	1,760
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	200	161	86,428	1.28	13	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	43	69	63,809	0.16	3	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	1,148	170	329,000	72.80	126	1,120
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	100	80	44,699	0.64	20	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	42	14	65,296	0.16	22	160
		TOTAL			3,795	6,628	1,380,234	219.83	272	4,800

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	5,824	24	28,457	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	19,712	22,915	5,199	--	1,760
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	4,544	6	919	10,336	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	1,056	2,656	5	698	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	7,840	2,800	116	--	1,120
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	-	1,696	--	16	800	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	1,056	1,568	--	23	--	160
		TOTAL			2,112	43,840	25,750	35,427	11,136	4,800

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	37,727	128,502	34,545	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	68,552	197,560	73,260	10,560	1,760
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	5,184	36,615	9,994	13,216	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	8,733	25,463	8,456	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	40,628	78,904	36,260	1,456	1,120
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	2,536	10,885	3,568	944	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	8,627	15,448	6,207	--	160
		TOTAL			171,988	493,377	172,289	26,176	4,800

TABLE B-12. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: HIGH LEVEL OF LOW-BTU GASIFICATION IN 2000

	EXTRACTION	PROCESSING	TRANS.	END USE	STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	0	0
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	1,120	1,483
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	640	800
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	0	0
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	320	389
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	0	0
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	1,280	2,363
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	0	0
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	160	200
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	160	197
11	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	1,120	1,951
				TOTAL	4,800	7,382

TABLE B-13. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: HIGH LEVEL OF LOW-BTU GASIFICATION IN 2000

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	810	4,899	308,202	53.27	22	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	528	449	175,200	33.28	24	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	200	161	86,428	1.28	13	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	342	554	518,471	1.28	20	1,280
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	164	24	47,000	10.40	18	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	100	80	44,699	0.64	20	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	297	101	457,073	1.12	154	1,120
		TOTAL			2,440	6,268	1,637,073	101.27	271	4,800

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	5,824	24	28,457	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	7,168	8,333	1,890	--	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	4,544	6	919	10,336	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	8,448	21,248	38	5,581	--	1,280
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	1,120	400	17	--	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	1,696	--	16	800	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	7,392	10,976	--	162	--	1,120
		TOTAL			15,840	52,576	8,801	37,041	11,136	4,800

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	37,727	128,502	34,545	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	24,928	71,840	26,640	3,840	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	5,184	36,615	9,994	13,216	320
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	69,866	203,708	67,646	--	1,280
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	5,804	11,272	5,180	208	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	2,536	10,885	3,568	944	160
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	60,386	108,136	43,450	--	1,120
		TOTAL			206,433	570,957	191,023	18,208	4,800

TABLE B-14. TRAJECTORIES, STEAM PRODUCTION, AND MINED-COAL REQUIREMENTS: HIGH LEVEL OF FLUIDIZED-BED COMBUSTION IN 2000

	EXTRACTION	PROCESSING	TRANS.	END USE	STEAM PROD, 10^{12} BTU/YR	MINED COAL REQUIRED 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	0	0
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	1,120	1,483
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	640	800
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	0	0
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	1,440	1,750
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	0	0
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	160	295
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	0	0
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	160	200
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	1,120	1,378
11	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	160	279
				TOTAL	4,800	6,185

TABLE B-15. TOTAL POLLUTANT DISCHARGES AND RESOURCE REQUIREMENTS BY TRAJECTORY: HIGH LEVEL OF FBC IN 2000

AIR POLLUTANTS

	EXTRACTION	PROCESSING	TRANS.	END USE	NO_x (MILL LB)	SO_2 (MILL LB)	CO_2 (MILL LB)	TOTAL ORGANIC MILL LB	PARTIC. (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	810	4,899	308,202	53.27	22	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	528	449	175,200	33.28	24	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	900	725	388,926	5.76	59	1,440
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	43	69	64,809	0.16	3	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	164	24	47,000	10.40	18	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	700	560	312,893	4.48	140	1,120
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	42	14	65,296	0.16	22	160
		TOTAL			3,187	6,740	1,362,326	107.51	288	4,800

SOLID WASTES

	EXTRACTION	PROCESSING	TRANS.	END USE	TAR (MILL LB)	ASH (MILL LB)	SLUDGE (MILL LB)	TAILINGS (MILL LB)	SPENT BED (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	--	5,824	24	28,457	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	--	7,168	8,333	1,890	--	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	--	20,448	27	4,136	46,512	1,440
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	1,056	2,656	5	698	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	--	1,120	400	17	--	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	--	11,872	--	112	5,600	1,120
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	1,056	1,568	--	23	--	160
		TOTAL			2,112	50,656	8,789	35,333	52,112	4,800

RESOURCE REQUIREMENTS

	EXTRACTION	PROCESSING	TRANS.	END USE	WATER (MILL. GAL)	LAND (ACRE)	LABOR (MEN)	RAW MATERIALS (MILL LB)	STEAM PROD 10^{12} BTU/YR
1.	EAST. UNDERGROUND, -		RAIL ,	-CONV COMB A ,	--	--	--	--	--
2.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-CONV COMB PCCA ,	37,727	128,502	34,545	--	1,120
3.	EAST. UNDERGROUND, -		RAIL ,	-FGD A ,	24,928	71,840	26,640	3,840	640
4.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FGD PCCA ,	--	--	--	--	--
5.	EAST. UNDERGROUND, -		RAIL ,	-FBC A ,	23,328	164,768	44,973	59,472	1,440
6.	EAST. UNDERGROUND, -	PHYS CL A,	-RAIL ,	-FBC PCCA ,	--	--	--	--	--
7.	EAST. UNDERGROUND, -		RAIL ,	-LOW BTU GASIF A ,	8,733	25,463	8,456	--	160
8.	WEST. STRIP MINE , -		RAIL ,	-CONV COMB B ,	--	--	--	--	--
9.	WEST. STRIP MINE , -		RAIL ,	-FGD B ,	5,804	11,272	5,180	208	160
10.	WEST. STRIP MINE , -		RAIL ,	-FBC B ,	17,752	76,195	24,976	6,608	1,120
11.	WEST. STRIP MINE , -		RAIL ,	-LOW BTU GASIF B ,	8,627	15,448	6,207	--	160
		TOTAL			126,899	493,488	150,977	70,128	4,800

APPENDIX C

AIR QUALITY STATUS AND INDUSTRIAL CONCENTRATION IN THE GULF COAST AND GREAT LAKES INDUSTRIAL BELTS

Material in this appendix addresses the air quality status, industrial boiler emissions, and correlations between the two for the seven states comprising the two industrial belts defined in Chapter 7.

AIR QUALITY VS. DENSITIES OF EMISSIONS FROM INDUSTRIAL BOILERS

Overall in both industrial belts, 154 counties out of a total of 755 are in partial or entire violation of the primary or secondary national standards for ambient air quality for TSP or SO_2. Of these 154 counties, 106 are in primary violation for TSP or SO_2. Information for the determinations has been provided by OAQPS (1). Figures C-1, C-2, and C-3 map those counties in the two industrial belts that are in non-attainment for TSP or SO_2. No counties in the two areas are in non-attainment for NO_x. There are no violations for SO_2 in the Gulf Coast Industrial Belt. The information included on the maps is current as of October 15, 1979, and reflects the recent redesignation of Trumbull and Mahoning counties in Ohio to attainment for SO_2. The maps should be referred to for much of the following discussion.

INDUSTRY IS CONCENTRATED

As an indicator of where industrial capacity is located in these two areas, maps of emissions from industrial boilers were constructed. Again using information from the NEDS file maintained by OAQPS (2), county-by-county industrial boiler emissions were calculated for the seven states in the industrial belts and expressed in a tons per square mile basis. Comparisons of relative emission densities provide an index of the concentration of industrial boilers. (The surrogate of emission densities was required because no other uniform data base exists for the information. Department of Commerce information for employment could have been used, but such an index would provide information on the concentration of industry, not the concentration of industrial boiler capacity.) Emissions for TSP and SO_2 were mapped for the Great Lakes Industrial Belt. Because of the heavy use of natural gas in the Gulf Coast Industrial Belt and the relatively low emissions of TSP and SO_2 from natural gas combustion, densities of NO_x emissions were also mapped for Texas and Louisiana.

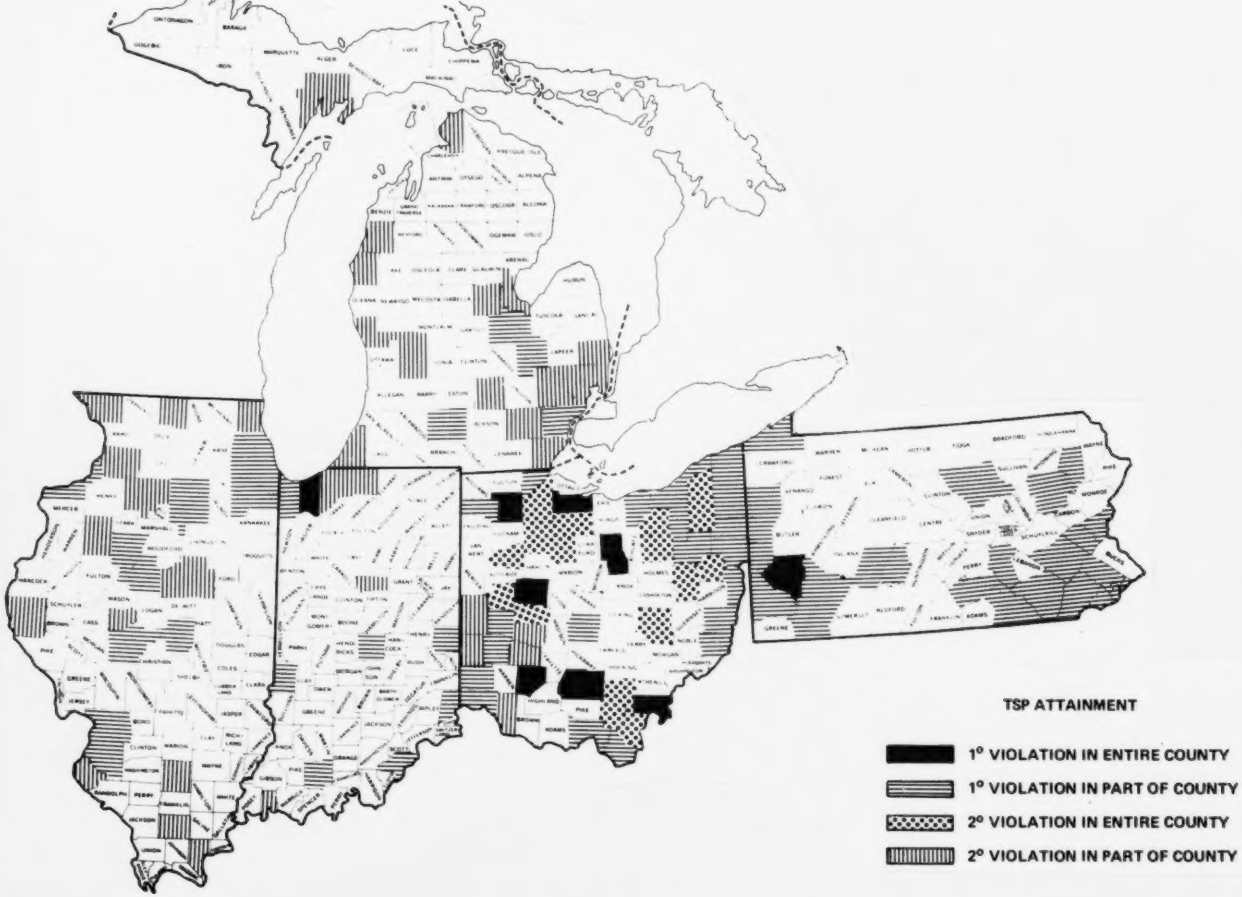
TSP ATTAINMENT
1° VIOLATION IN ENTIRE COUNTY
1° VIOLATION IN PART OF COUNTY
2° VIOLATION IN ENTIRE COUNTY
2° VIOLATION IN PART OF COUNTY

Figure C-1. TSP attainment status for the Great Lakes Industrial Belt, 1979.

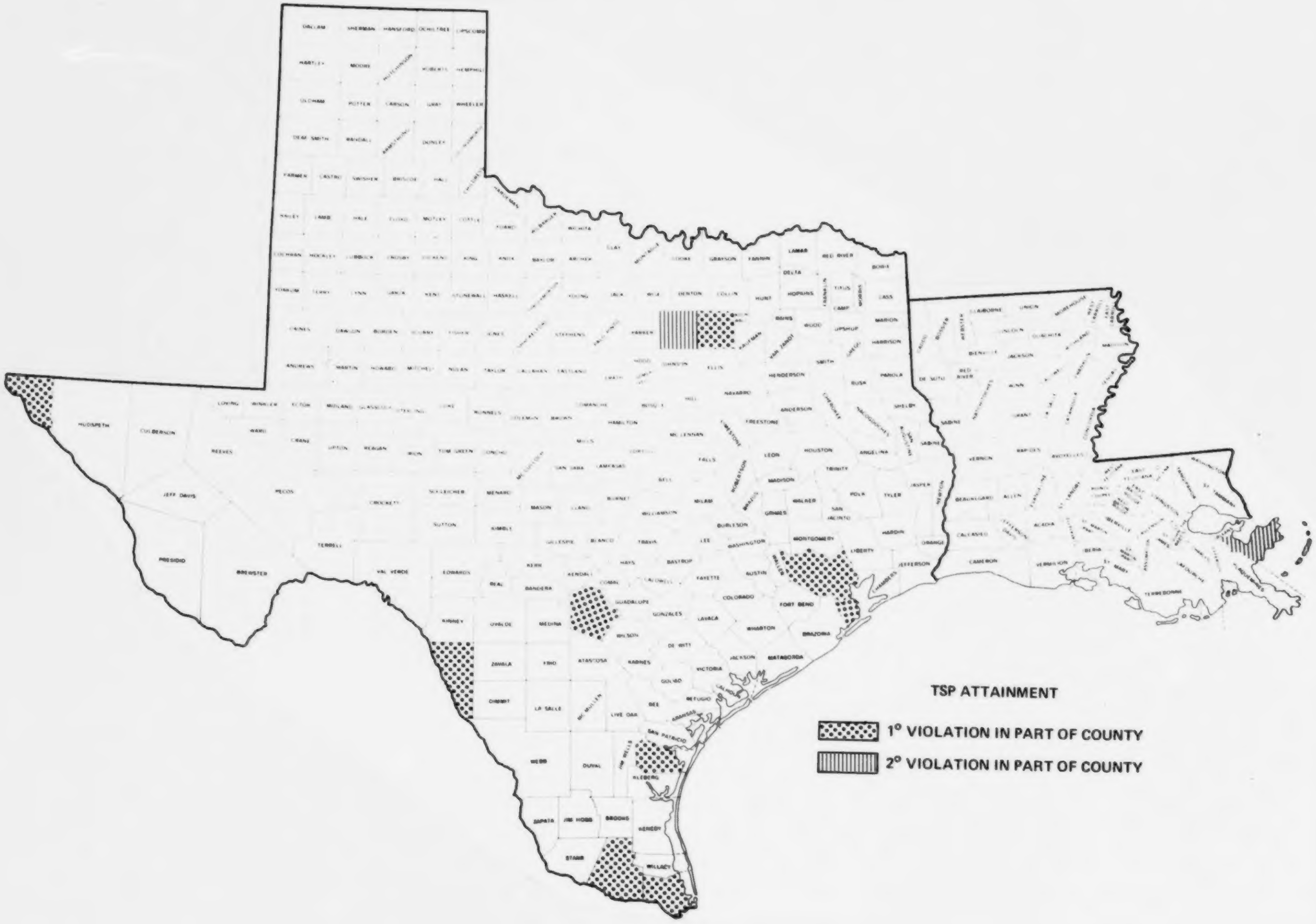
TSP ATTAINMENT
▩ 1° VIOLATION IN PART OF COUNTY
▥ 2° VIOLATION IN PART OF COUNTY

Figure C-2. TSP attainment status for the Gulf Coast Industrial Belt, 1979.

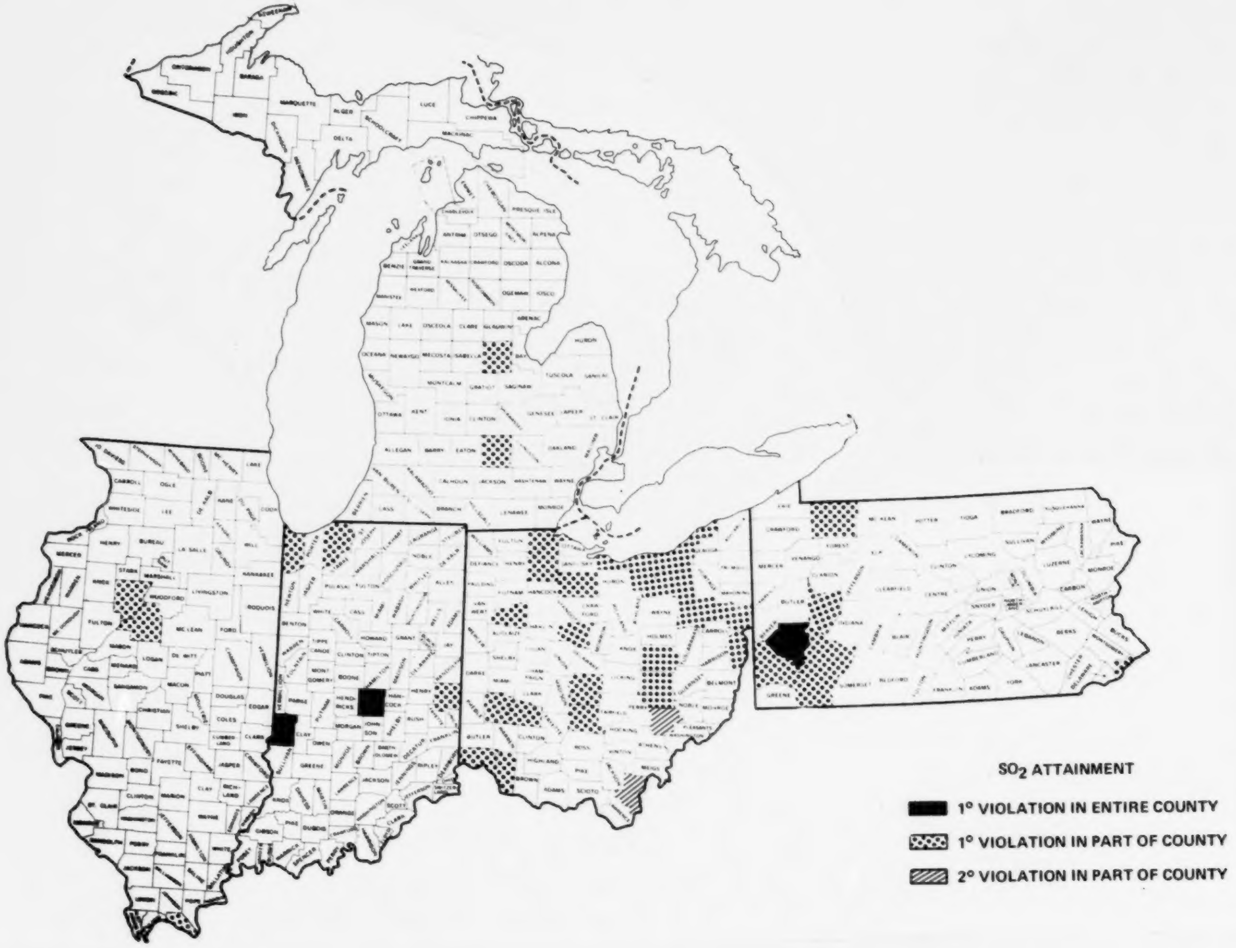
SO₂ ATTAINMENT
1° VIOLATION IN ENTIRE COUNTY
1° VIOLATION IN PART OF COUNTY
2° VIOLATION IN PART OF COUNTY

Figure C-3. SO_2 attainment status for the Great Lakes Industrial Belt, 1979.

The maps of emission densities are displayed in Figures C-4 through C-8. In total, the counties marked on the TSP and SO_2 maps represent the location of 90 to 95 percent of both belts' industrial capacity as measured by emissions from major sources. State-by-state emission figures are provided in Tables C-1 and C-2. Because of the large amount of industrial capacity in the two belts, the same counties also account for 40 to 45 percent of nationwide capacity. What is most apparent from these maps is the concentration of industry in relatively restricted geographical areas. Taken in concert, all counties marked on the maps represent about one-sixth of the total land area in the two industrial belts. For the highest category of emission densities (that is, the "Blackened" counties), less than four percent of the total land area is represented. Sixty-five to seventy-five percent of total industrial capacity in the industrial belts occurs within these highest emission density counties.

In the Great Lakes Industrial Belt, the counties marked on the map of TSP emissions (Figure C-4) represent 95 percent of all TSP emissions from industrial boilers that are also major sources; 87 percent of major source emissions of SO_2 are also captured. On the same map, emission densities greater than 11 tons per square mile* (the most concentrated category) reflect 70 percent of TSP emissions and about 55 percent of SO_2 emissions. Thus, much greater than half of industrial capacity as measured by emissions occurs in 22 counties out of a total of 436, and about 90 percent of capacity occurs in about 85 counties.

Using emission densities of SO_2 for the same region produces similar concentrations. The SO_2 map (Figure C-6) captures about 90 percent of capacity in the approximately 75 counties that are shaded, with approximately 60 percent of capacity indicated in 20 counties for the highest SO_2 emission category of 35 tons per square mile or greater. A comparison of Figures C-4 and C-6 demonstrates that, by and large, those counties with marked TSP emissions from industrial boilers are about the same counties marked on the SO_2 map.

For the Gulf Coast Industrial Belt, the NO_x emissions map (Figure C-8) provides the best indication of where the majority of industrial boiler capacity is concentrated. In Figure C-8, 80 percent of all TSP, 97 percent of all SO_2, and 96 percent of all NO_x emissions from industrial boilers arise from the shaded counties. A rough estimate, therefore, would be that about 90 percent of major industrial capacity is located in the same counties. For the highest category of NO_x emissions densities, that is, greater than 15 tons per square mile, 20 percent of TSP, 40 percent of SO_2, and 60 percent of NO_x emissions are captured for Texas and Louisiana. When Figure C-8 is used in conjunction with Figures C-5 (TSP) and C-7 (SO_2), a fairly clear picture of industrial capacity in the Gulf Coast begins to emerge. Note the prevalence

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*The actual densities of emissions chosen as cutoffs in Figures C-4 through C-8 were determined on a percentile basis. That is, break points in emission densities were desired that accounted for the most amount of emissions from the fewest counties for each category.

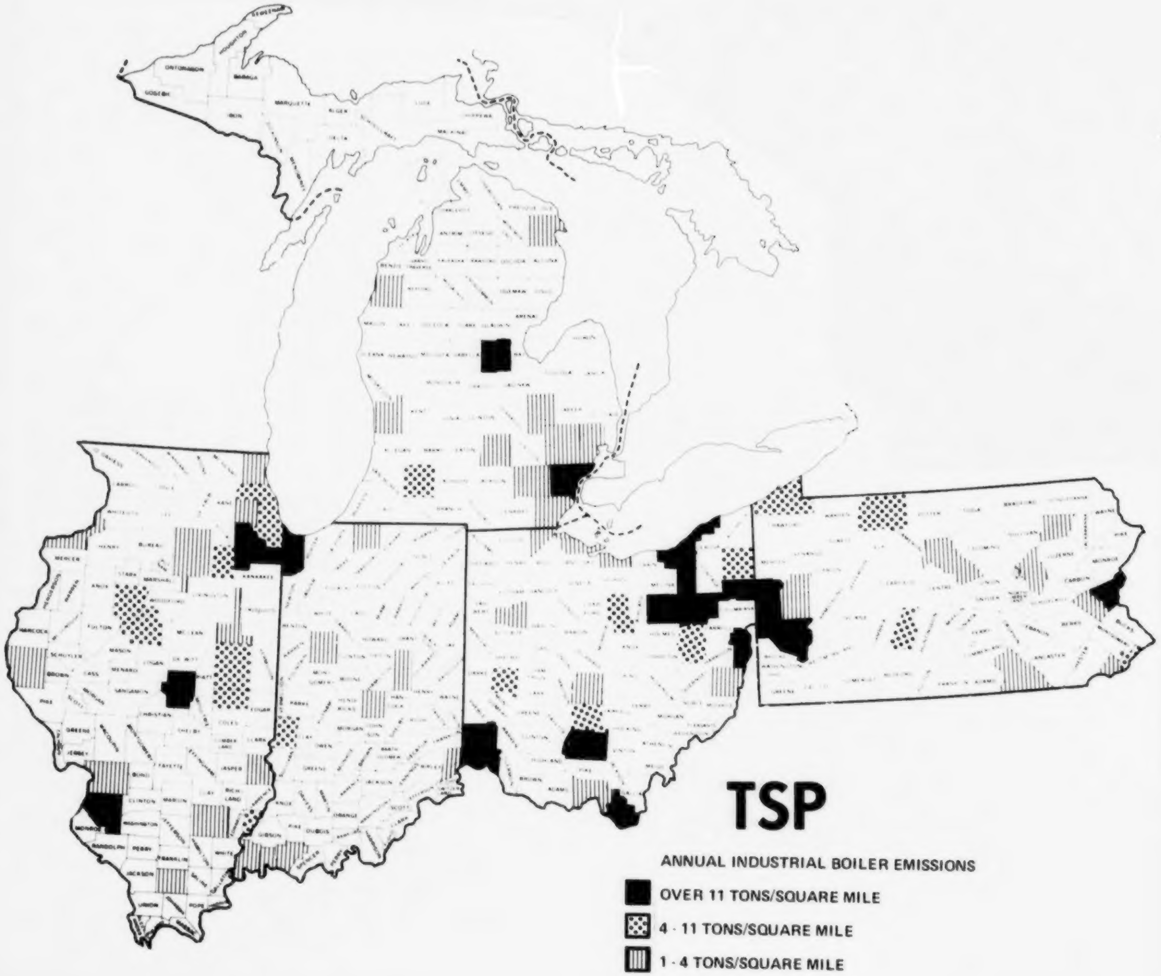
TSP
ANNUAL INDUSTRIAL BOILER EMISSIONS
■ OVER 11 TONS/SQUARE MILE
▨ 4 - 11 TONS/SQUARE MILE
▥ 1 - 4 TONS/SQUARE MILE

Figure C-4. Great Lakes Industrial Belt county-by-county industrial boiler emissions for TSP.

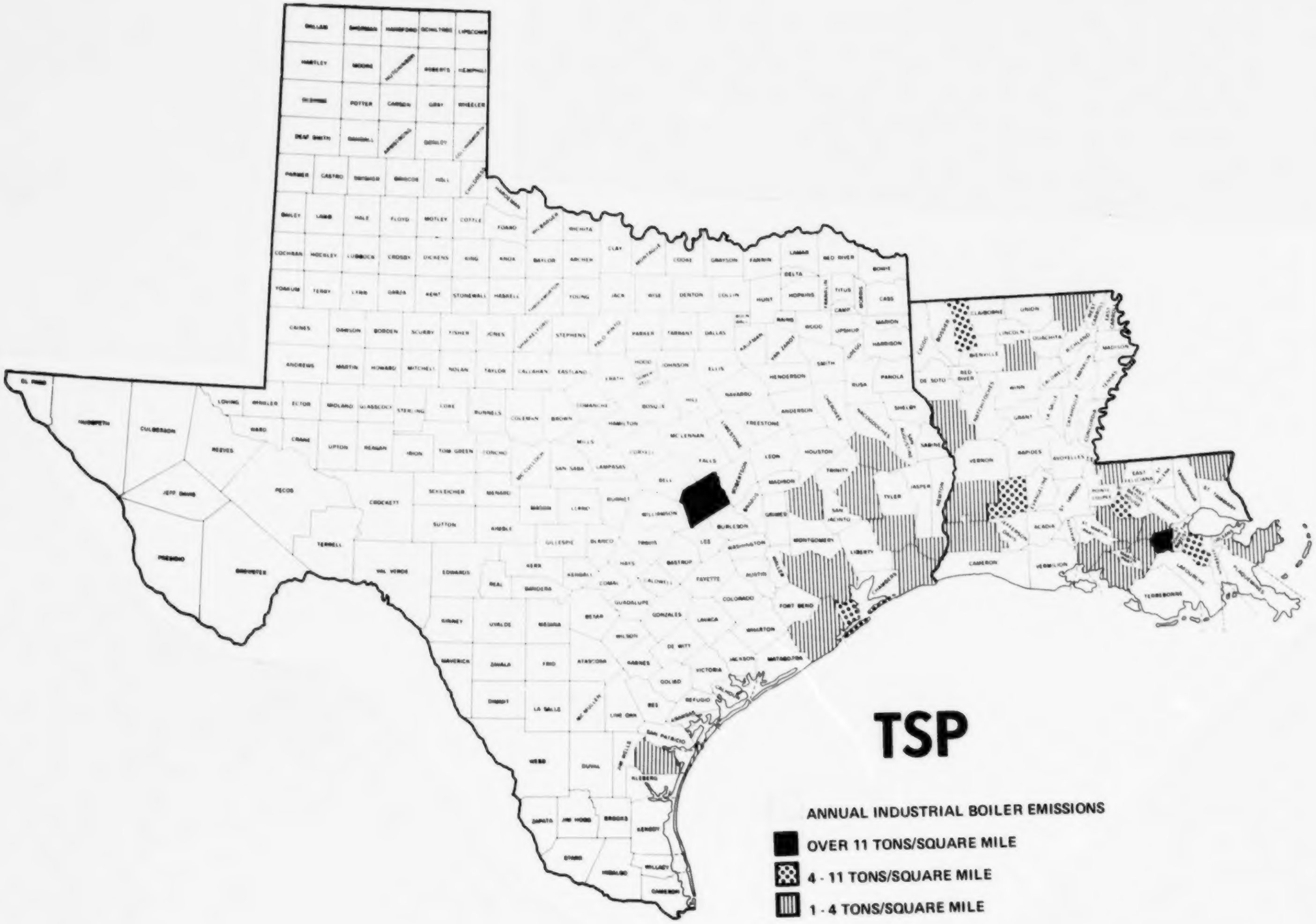
TSP
ANNUAL INDUSTRIAL BOILER EMISSIONS
■ OVER 11 TONS/SQUARE MILE
▩ 4 - 11 TONS/SQUARE MILE
▥ 1 - 4 TONS/SQUARE MILE

Figure C-5. Gulf Coast Industrial Belt county-by-county industrial boiler emissions for TSP.

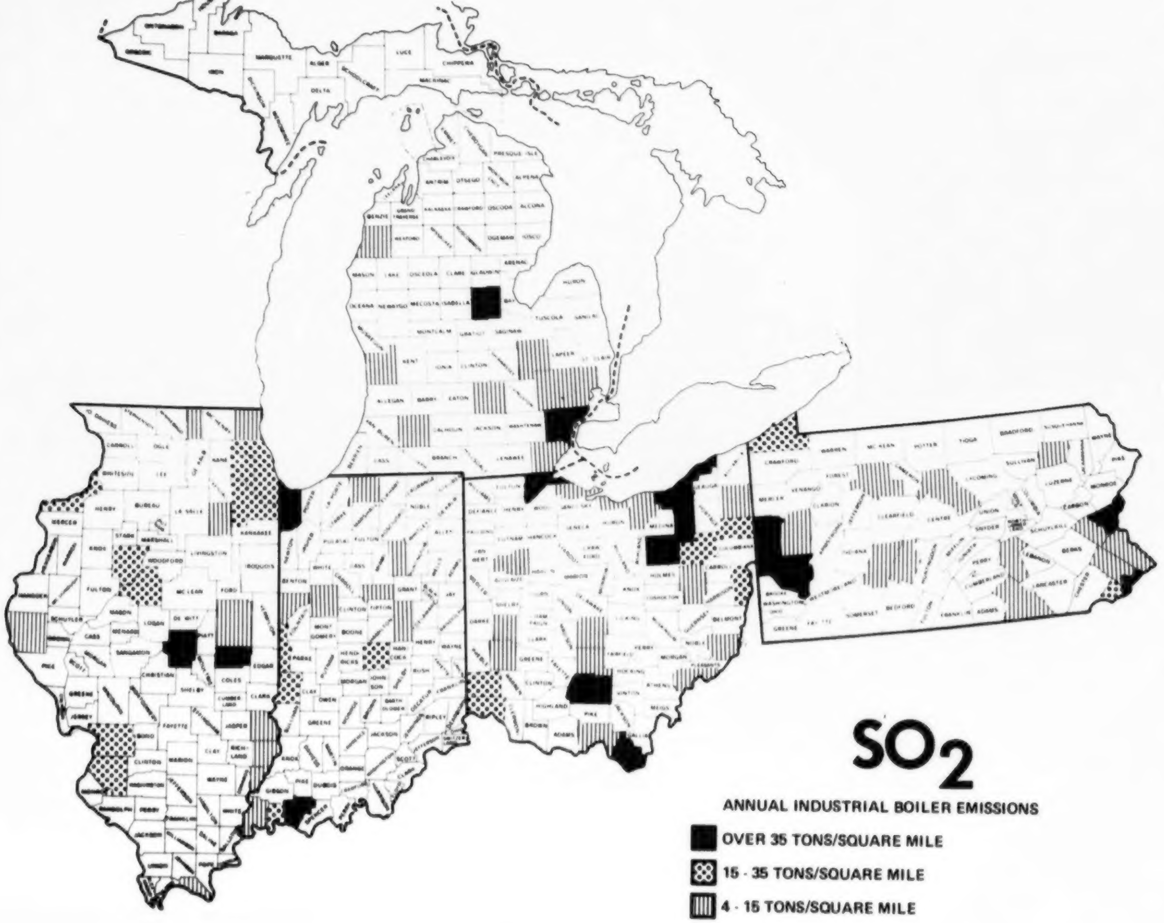
SO2
ANNUAL INDUSTRIAL BOILER EMISSIONS
■ OVER 35 TONS/SQUARE MILE
▩ 15 - 35 TONS/SQUARE MILE
▥ 4 - 15 TONS/SQUARE MILE

Figure C-6. Great Lakes Industrial Belt county-by-county industrial boiler emissions for SO_2.

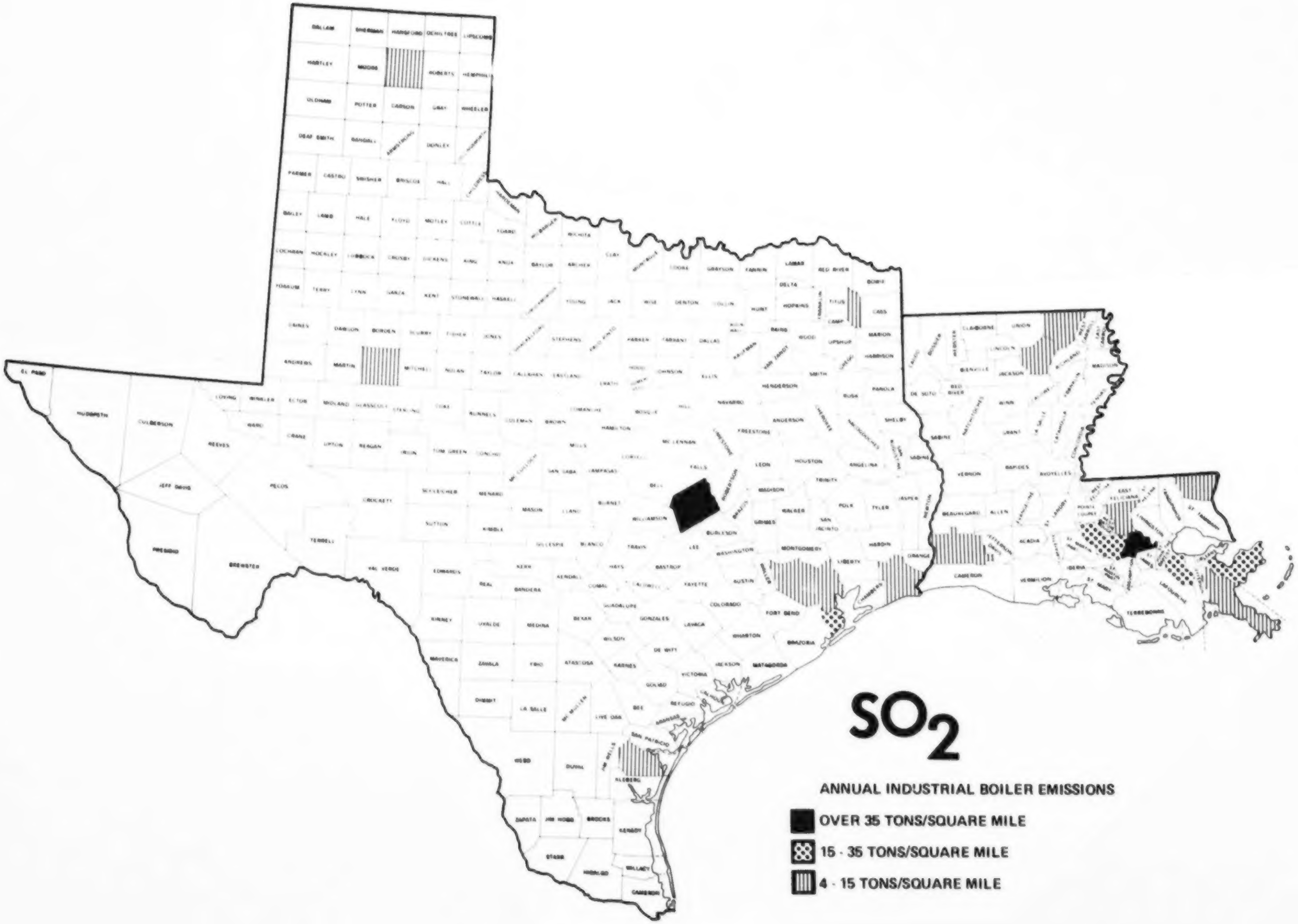
SO2
ANNUAL INDUSTRIAL BOILER EMISSIONS
■ OVER 35 TONS/SQUARE MILE
▨ 15 - 35 TONS/SQUARE MILE
▥ 4 - 15 TONS/SQUARE MILE

Figure C-7. Gulf Coast Industrial Belt county-by-county industrial boiler emissions for SO_2.

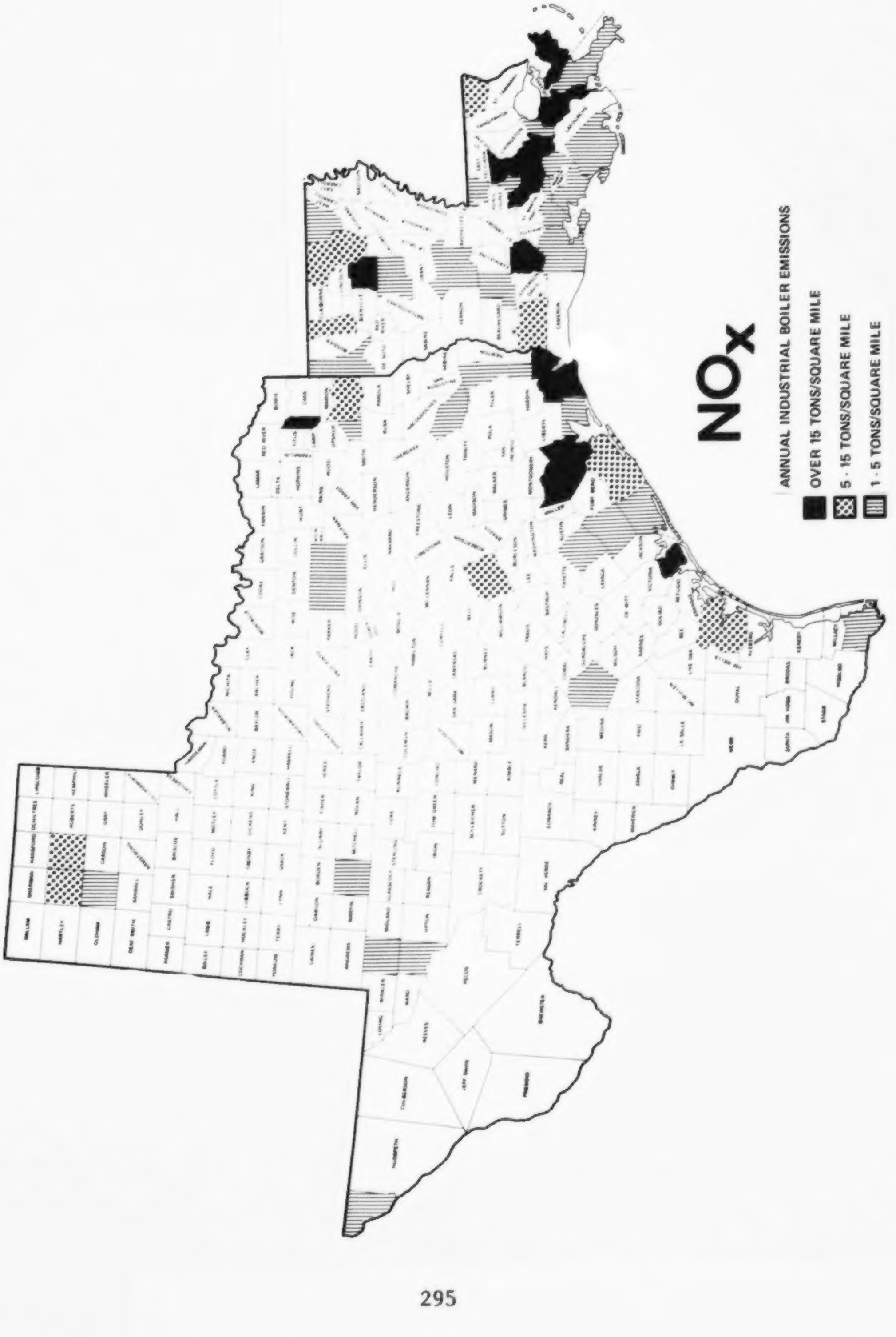
NOx
ANNUAL INDUSTRIAL BOILER EMISSIONS
■ OVER 15 TONS/SQUARE MILE
▩ 5 - 15 TONS/SQUARE MILE
▤ 1 - 5 TONS/SQUARE MILE

Figure C-8. Gulf Coast Industrial Belt county-by-county industrial boiler emissions for NO_x.

TABLE C-1. TSP EMISSION IN NON-ATTAINMENT COUNTIES

	TSP violating counties		SO_2 violating counties		TSP & SO_2 violations*	
State	10^3 Tons	% of Total	10^3 Tons	% of Total	10^3 Tons	% of Total
Great Lakes Region						
Illinois						
1°**	61.6	70	9.6	11	61.6	70
2°**	4.1	5	0	0	4.1	5
1° + 2°	65.7	75	9.6	11	65.7	75
Indiana						
1°	12.3	62	11.5	58	12.4	62
2°	1.1	6	0	0	1.1	6
1° + 2°	13.4	68	11.5	58	13.5	68
Michigan						
1°	10.7	34	7.0	23	17.6	59
2°	11.6	39	0	0	11.5	39
1° + 2°	22.2	75	7.0	23	22.2	75
Ohio						
1°	117.6	82	83.5	62	119.8	86
2°	14.4	11	0	0	14.4	11
1° + 2°	126.2	93	83.5	62	129.4	95
Pennsylvania						
1°	167.6	92	20.4	11	169.0	92
2°	1.2	1	0	0	1.2	1
1° + 2°	168.7	92	20.4	11	169.0	92
Total						
1°	364.0	80	132.0	29	377.5	83
2°	32.4	7	0	0	32.4	7
1° + 2°	396.4	87	132.0	29	399.9	88
Gulf Coast Region						
Louisiana						
1°	0	0	0	0	0	0
2°	0	0	0	0	0	0
1° + 2°	0	0	0	0	0	0
Texas						
1°	41.6	18	46.0	37	64.8	28
2°	neg.	0	0.4	1	0.4	1
1° + 2°	41.6	18	46.5	38	68.6	30
Total						
1°	41.6	9	46.0	23	64.8	14
2°	neg.	0	0.4	0	0.4	0
1° + 2°	41.6	9	46.5	23	68.6	15
Total Both Regions						
1°	405.6	59	178.0	26	442.3	65
2°	32.4	5	0.4	0	32.8	5
1° + 2°	438.0	64	178.4	26	468.5	68

*Total may not add because some counties are in both TSP and SO_2 non-attainment.
**1° = primary non-attainment; 2° = secondary non-attainment.

TABLE C-2. SO_2 EMISSION IN NON-ATTAINMENT COUNTIES

State	TSP violating counties		SO_2 violating counties		TSP & SO_2 violations	
	10^3 Tons	% of Total	10^3 Tons	% of Total	10^3 Tons	% of Total
Great Lakes Region						
Illinois						
1°**	149.9	70	30.1	14	153.2	72
2°**	11.8	6	0	0	11.8	6
1° + 2°	161.7	76	30.1	14	165.0	77
Indiana						
1°	85.3	55	78.4	51	85.6	56
2°	10.8	7	0	0	10.8	7
1° + 2°	96.1	62	78.4	51	96.1	62
Michigan						
1°	34.7	28	40.8	33	75.5	61
2°	61.4	50	0	0	61.4	50
1° + 2°	96.1	78	40.8	33	96.1	78
Ohio						
1°	330.4	86	277.8	72	346.9	90
2°	44.9	12	0	0	44.9	12
1° + 2°	375.3	97	277.8	72	379.3	98
Pennsylvania						
1°	457.6	88	65.9	13	470.3	90
2°	9.0	2	0	0	9.0	2
1° + 2°	466.6	90	65.9	13	470.3	90
Total						
1°	1057.9	76	492.9	35	1131.5	81
2°	137.9	10	0	0	137.9	10
1° + 2°	1195.8	85	492.9	35	1206.8	86
Gulf Coast Region						
Louisiana						
1°	0	0	0	0	0	0
2°	0	0	0	0	0	0
1° + 2°	0	0	0	0	0	0
Texas						
1°	46.0	37	0	0	46.0	37
2°	0.4	0	0	0	0.4	0
1° + 2°	46.5	38	0	0	46.5	38
Total						
1°	46.0	23	0	0	46.0	23
2°	0.4	0	0	0	0.4	0
1° + 2°	46.5	23	0	0	46.5	23
Total Both Regions						
1°	1103.9	69	492.9	31	1177.5	74
2°	138.3	9	0	0	138.3	9
1° + 2°	1242.3	78	492.9	31	1253.3	78

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*Total may not add because some counties are in both TSP and SO_2 non-attainment.
**1° = primary non-attainment; 2° = secondary non-attainment.

of industrial concentration on the Gulf Coast itself. Less than one-sixth of the counties in the Gulf Coast Industrial Belt contain 90 percent of industrial boiler capacity.

Overall, about 65 to 70 percent of industrial emissions from boilers come from counties in primary or secondary non-attainment for TSP or SO_2. This striking correlation is obtained by overlaying those counties with marked emission densities (Figures C-4 to C-8) on the counties displayed in Figures C-1 to C-3, the maps of NAAQS violations, and calculating the county-by-county emissions summarized by state in Tables C-1 and C-2. In the Great Lakes Industrial Belt, about 85 percent of major industrial point sources are located in TSP or non-attainment counties, with figures as high as 98 percent for some states, such as Ohio. Over 80 percent of TSP emissions from industrial boilers in the Great Lakes Industrial Belt occur in primary non-attainment counties; close to 90 percent occur in counties in both primary and secondary non-attainment. While there are considerably fewer non-attainment counties for SO_2 than TSP, still one-third of SO_2 emissions from industrial boilers in the belt take place in counties in primary non-attainment for SO_2. On a county-by-county basis, 16 out of the 19 counties with the highest SO_2 densities from industrial boilers are in partial or entire non-attainment for SO_2. For the highest TSP emission density counties, 21 out of 21 counties are in TSP non-attainment. For all counties that are shaded because of high emission densities, roughly 70 percent are in non-attainment, with over half in primary non-attainment for either TSP or SO_2.

The Gulf Coast Industrial Belt presents a somewhat different picture. First, no non-attainments for SO_2 occur in the region. Second, there are no TSP violating counties in Louisiana. Nevertheless, 8 out of the 10 counties in non-attainment for TSP are shaded in the map of NO_x emissions from industrial boilers (Figure C-8). Approximately 15 to 20 percent of the belt's industrial boiler capacity is located in counties with TSP violations. About the same percent of SO_2 emissions occur in those counties as well.

The remarkable consistency between industrial boiler emission densities and TSP and SO_2 non-attainment status for the counties under investigation led to posing the question: What is the status for the other counties which show high emission densities but are apparently in attainment? Initially, the supposition was that many of these counties may be "unclassified." The EPA publishes periodically in the Federal Register statewide summaries of area attainment designations. Investigation of these listings (3), however, demonstrated that only 5 out of 58 counties with high emission densities yet not located in partial or entire TSP or SO_2 non-attainment counties were unclassified. In working with the individual county data, however, the general observation was that the industrial boiler emissions correlated much better to non-attainment status than did total emissions. Frequently, for example, large electric utility emissions could cause high total emissions for a county, yet it would not be in non-attainment. While realizing that modeling with good monitoring data is the only accepted and validated method for predicting air quality, the fact that industrial boilers tend to be smaller than electric utility boilers and thus generally have shorter stacks, could tend to skew the importance of industrial boiler emissions to local air quality.

To gain a better fix on those counties with high emissions yet apparently in attainment, each of the 58 counties was checked with respect to its air quality monitoring status (4, 5, 6, 7). Specific county-by-county comments are offered in Table C-3. The surprising result obtained is that only six out of the 58 counties with high emission densities had sufficient monitoring data in the county to demonstrate attainment. Of these six, only one had an emission density in the two highest categories listed in Figures C-4 through C-8. With the exception of these six counties, the remaining counties with high emission densities for TSP or SO_2, but which did not have non-attainment status, are unclassified, have invalidated air quality monitoring, have had no air quality monitoring, or show apparent violations. About 70 percent of the 58 counties have no monitors for the particular emission for which they have high industrial boiler emission densities. Four additional counties indicate a possible violation of the TSP or SO_2 national standards for ambient air quality.

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3. National Air Data Branch. 1978. Air quality data--1977 Annual statistics. Monitoring and Data Analysis Division, U.S. Environmental Protection Agency. EPA-450/2-78-040 (NTIS No. PB 295816).

4. Federal Register 1978. pp. 8962-9037.

5. Federal Register 1978. pp. 40412-40420.

6. Federal Register 1978. pp. 40502-40516.

7. Federal Register 1979. pp. 5119-5128.

TABLE C-3. HIGH EMISSION DENSITY COUNTIES NOT SHOWING NAAQS VIOLATIONS

State/County	Rank[a]	TSP comments	Rank[a]	SO_2 comments
Illinois				
Boone	1	No TSP monitor	1	No TSP monitor
Champaign	2	Unclassified, possible violation	1	No monitor
Crawford	1	No monitor	1	No monitor
Douglas	2	No monitor	3	No monitor
Ford	1	No monitor		
Grundy		Unclassified, no monitor	1	No monitor
Lawrence		No monitor	1	No monitor
Wayne	1	No monitor		
Indiana				
Madison	1	OK	1	No monitor
Posey	1	No monitor	1	No monitor
Tippecanoe		No monitor	1	OK
Vermilion		No monitor	2	No monitor
Wabash			1	No monitor
Warren		No monitor	1	No monitor
Warrich	1	No monitor	3	Unclassified
Louisiana				
Allen	2	No monitor	3	No monitor
Ascension	1	No monitor		
Assumption	1	No monitor		
Beauregard	1	No monitor		
Calscieu	1	OK	1	OK
East Baton Rouge			1	OK
Iberia	1	No monitor		
Iberville	1	OK	2	OK
Jackson	1	No monitor		
Morehouse	1	No monitor	1	No monitor
Ouachita			1	OK
Plaquemines			1	No monitor
St. Bernard	1	2° violation shown	2	No monitor
St. Charles	2	No monitor	2	No monitor
St. Mary	1	No monitor		
Sabine	1	No monitor		
Washington	1	No monitor	1	No monitor
Webster	2	No violation, questionable monitor		
West Baton Rouge	2	No monitor		
West Feliciana	1	No monitor		
Michigan				
Alpens	1	No monitor		
Kalamazoo	2	OK	1	OK
Ottawa	1	OK	1	No monitor
Ohio				
Ottawa	1	No monitor	1	No monitor
Pennsylvania				
Butter	1	No monitor	1	No monitor
Clinton	1	No monitor	1	No monitor
Columbia	1	No monitor		
Delaware	1	Unclassified, All values??		
Elk			1	No monitor
McKann	2	No monitor		
Wyoming	1	No monitor	1	No monitor
Texas				
Angelina	1	No monitor		
Brazoria	1	1°, 2° violation shown		
Ector	1	1° violation shown		
Hardin	1	No monitor		
Howard		2° violation shown	1	OK
Hutchinson			1	No monitor
Jefferson	1	2° violation shown	1	OK
Milam	3	No monitor	1	No monitor
Morris			1	No monitor
Orange	1	3-hr exceeded		
Polk	1	No monitor		
Walker	1	Questionable monitor		

[a] 1= lowest, 3 = highest emission density displayed in Figures C-4 through C-8.